UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2004

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to .

Commission File No. 1-2745

Southern Natural Gas Company
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**63-0196650** (I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas** (Address of principal executive offices)	**77002** (Zip Code)

Telephone Number: (713) 420-2600

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

State the aggregate market value of the voting stock held by non-affiliates of the registrant: None

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock, par value $1 per share. Shares outstanding on March 29, 2005: 1,000

SOUTHERN NATURAL GAS COMPANY MEETS THE CONDITIONS OF GENERAL INSTRUCTION I(1)(a) AND (b) TO FORM 10-K AND IS THEREFORE FILING THIS REPORT WITH A REDUCED DISCLOSURE FORMAT AS PERMITTED BY SUCH INSTRUCTION.

Documents Incorporated by Reference: None

SOUTHERN NATURAL GAS COMPANY

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* We have not included a response to this item in this document since no response is required pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day	MDth	= thousand dekatherms
BBtu	= billion British thermal units	MMcf	= million cubic feet
Bcf	= billion cubic feet		

When we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to "us", "we", "our", or "ours", we are describing Southern Natural Gas Company, and/or our subsidiaries.

PART I

ITEM 1. BUSINESS

General

We are a Delaware corporation incorporated in 1935. In October 1999, we became a wholly owned subsidiary of El Paso Corporation (El Paso) through the merger of Sonat Inc. with El Paso. Our primary business consists of the interstate transportation and storage of natural gas. We conduct our business activities through our natural gas pipeline systems, which include our Southern Natural Gas pipeline system and our 50 percent ownership interest in Citrus Corp. (Citrus), our liquefied natural gas (LNG) receiving terminal and our storage facilities as discussed below.

The Pipeline Systems. The Southern Natural Gas system consists of approximately 8,000 miles of pipeline with a design capacity of approximately 3,437 MMcf/d. During 2004, 2003 and 2002, average throughput was 2,163 BBtu/d, 2,101 BBtu/d and 2,151 BBtu/d. Our interstate pipeline system extends from natural gas fields in Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham. We are the principal natural gas supplier to the growing southeastern markets of Alabama and Georgia. Since 2001, the Federal Energy Regulatory Commission (FERC) has approved and we have placed in service our South System I, South System II and North System II expansions. These expansions make up approximately 700 MMcf/d of our total design capacity.

We also have a 50 percent ownership interest in Citrus, a Delaware corporation. Citrus owns 100 percent of the Florida Gas Transmission system, which consists of approximately 4,870 miles of pipeline with a design capacity of 2,082 MMcf/d. During 2004, 2003 and 2002, average throughput was 2,014 BBtu/d, 1,963 BBtu/d and 2,004 BBtu/d. This system extends from south Texas to south Florida. For more information regarding our investment in Citrus and the Florida Gas Transmission system, see Part II, Item 8, Financial Statement and Supplementary Data, Note 11 as well as Citrus' audited financial statements and related notes beginning on page 43 of this Form 10-K.

LNG Terminal. Our wholly owned subsidiary, Southern LNG Inc. (SLNG), owns an LNG receiving terminal, located on Elba Island, near Savannah, Georgia, which is capable of achieving a peak sendout of 675 MMcf/d and a base load sendout of 446 MMcf/d. The terminal was placed in service and began receiving deliveries in December 2001, after having been idle for a number of years. The capacity at the terminal is contracted with a subsidiary of British Gas, BG LNG Services, LLC. In 2003, the FERC approved our plan to expand the peak sendout capacity of the Elba Island facility by 540 MMcf/d and the base load sendout by 360 MMcf/d (for a total peak sendout capacity once completed of 1,215 MMcf/d and a base load sendout of 806 MMcf/d). The expansion is estimated to cost approximately $157 million and has a planned in-service date of February 2006.

Storage Facilities. Along our Southern Natural Gas pipeline system, we have approximately 60 Bcf of underground working natural gas storage capacity through our Muldon storage facility in Monroe County, Mississippi, which has a storage capacity of 31 Bcf, and our 50 percent interest in Bear Creek Storage Company (Bear Creek), with our proportionate share of storage capacity of 29 Bcf.

Bear Creek is a joint venture that we own equally with our affiliate, Tennessee Storage Company (TSC), a subsidiary of Tennessee Gas Pipeline Company (TGP), also our affiliate. Bear Creek owns and operates an underground natural gas storage facility located in Louisiana. The facility has a capacity of 50 Bcf of base gas and 58 Bcf of working storage. Bear Creek's working storage capacity is committed equally to TGP and us under long-term contracts.

Regulatory Environment

Our interstate natural gas transmission system, storage and terminalling operations are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Our pipeline systems, LNG terminal and storage facilities operate under FERC-approved tariffs that establish rates, terms and conditions for service to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage and terminalling;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between pipeline and energy affiliates;
- terms and conditions of services;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

The fees or rates established under our tariffs are a function of our costs of providing services to our customers, and include provisions for a reasonable return on our invested capital. Approximately 94 percent of our 2004 transportation services and storage revenue is attributable to reservation charges paid by firm customers. Firm customers are those who are obligated to pay a monthly reservation charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. The remaining six percent of our transportation services and storage revenue is variable. Due to our regulated nature and the high percentage of our revenues attributable to reservation charges our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as changes in natural gas prices and market conditions, regulatory actions, competition, weather and the creditworthiness of our customers. We also experience volatility in our financial results when the amounts of natural gas and electricity utilized in operations differ from the amounts we receive for those purposes.

Our interstate pipeline systems and LNG terminal are also subject to federal, state and local statutes and regulations regarding pipeline and LNG plant safety and environmental matters. Our systems have ongoing inspection programs designed to keep all of our facilities in compliance with environmental and pipeline safety requirements. We believe that our systems are in material compliance with the applicable requirements.

We are subject to regulation over the safety requirements in the design, construction, operation and maintenance of our interstate natural gas transmission system and storage facilities by the U.S. Department of Transportation. Our operations on U.S. government land are regulated by the U.S. Department of the Interior and our LNG terminalling business is regulated by the U.S. Coast Guard.

A discussion of our significant rate and regulatory matters is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 7 and is incorporated herein by reference.

Markets and Competition

Our markets consist of distribution and industrial companies, electric generation companies, natural gas producers, other natural gas pipelines, and natural gas marketing and trading companies. We provide transportation and storage services in both our natural gas supply and market areas. Our pipeline system connects with multiple pipelines that provide our shippers with access to diverse sources of supply and various natural gas markets serviced by these pipelines.

A number of large natural gas consumers are electric utility companies who use natural gas to fuel electric power generation facilities. Electric power generation is the fastest growing demand sector of the natural gas market. The growth and development of the electric power industry potentially benefit the natural gas industry by creating more demand for natural gas turbine generated electric power, but this effect is offset, in varying degrees, by increased generation efficiency, the more effective use of surplus electric capacity and increased natural gas prices. The increase in natural gas prices, driven in part by increased demand from the power sector, has diminished the demand for natural gas in the industrial sector. In addition, in several regions of the country, new additions in electric generation capacity have exceeded load growth and transmission capabilities out of those regions. These developments may inhibit owners of new power generation facilities from signing firm contracts with us.

Imported LNG is one of the fastest growing supply sectors of the natural gas market. Terminals and other regasification facilities can serve as important sources of supply for pipeline customers, enhancing the delivery capabilities and operational flexibility, and complementing traditional supply transported into market areas.

Our existing transportation and storage contracts mature at various times and in varying amounts of throughput capacity. Our ability to extend our existing contracts or remarket expiring capacity is dependent on competitive alternatives, access to capital, the regulatory environment at the local, state and federal levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. While we are allowed to negotiate contracts at fully subscribed quantities and at maximum rates allowed under our tariffs, we must, at times, discount our contracts to remain competitive.

The following table details the markets we serve and the competition on our Southern Natural Gas pipeline system as of December 31, 2004:

Customer Information	Contract Information	Competition
Approximately 230 firm and interruptible customers	Approximately 203 firm contracts Weighted average remaining contract term of approximately five years.[1]	We face strong competition in a number of our key markets. We compete with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on our system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil. Our four largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. Also, we compete with several pipelines for the transportation business of many of their other customers. In addition, we compete with pipelines and gathering systems for connection to new supply sources.
Major Customers:		
Atlanta Gas Light Company[1][2] (972 BBtu/d)	Contract terms expire in 2005-2007.	
Southern Company Services (418 BBtu/d)	Contract terms expire in 2010-2018.	
Alabama Gas Corporation (415 BBtu/d)	Contract terms expire in 2006-2013.	
Scana Corporation (346 BBtu/d)	Contract terms expire in 2005-2019.	

(1) On March 1, 2005, we and Atlanta Gas Light Company closed a transaction for the sale of facilities, under which Atlanta Gas Light Company agreed to extend its firm contracts for terms of 2008-2015. The effective date of such extensions is expected to be August 1, 2005, which will increase the weighted average remaining contract term for Atlanta Gas Light to approximately 6.5 years.

(2) Atlanta Gas Light Company is currently releasing a significant portion of its firm capacity to a subsidiary of Scana Corporation and to an affiliate of Southern Company Services under terms allowed by our tariff.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 7, and is incorporated herein by reference.

Employees

As of March 24, 2005, we had approximately 480 full-time employees, none of whom are subject to a collective bargaining arrangement.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interest in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 7, and is incorporated herein by reference.

In June 2003, we notified the Louisiana Department of Environmental Quality (LDEQ) that we had discovered possible compliance issues with respect to operations at our Toca Compressor Station. In December 2003, the LDEQ issued a Consolidated Compliance Order and Notice of Potential Penalty. Our Toca Compressor Station will invest an estimated $6 million to upgrade the station's environmental controls and the upgrade will be completed in early 2005. We filed a revised permit application and plan for compliance in January 2004 and paid a penalty of $66,000, resolving the matter.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Item 4, Submission of Matters to a Vote of Security Holders, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

All of our common stock, par value $1 per share, is owned by El Paso and, accordingly, our stock is not publicly traded.

We pay dividends on our common stock from time to time from legally available funds that have been approved for payment by our Board of Directors. In March 2003, in connection with El Paso's contribution of its interest in Citrus to us, we declared and paid a $600 million dividend, $310 million of which was a distribution of affiliated receivables and $290 million of which was cash. No common stock dividends were declared or paid in 2004 or 2002.

ITEM 6. SELECTED FINANCIAL DATA

Item 6, Selected Financial Data, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information required by this Item is presented in a reduced disclosure format pursuant to General Instruction I to Form 10-K. The notes to our consolidated financial statements contain information that is pertinent to the following analysis, including a discussion of our significant accounting policies. As discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 1 our financial statements for the years ended December 31, 2003 and 2002 have been restated for the manner in which we originally applied the provisions of Statements of Financial Accounting Standards (SFAS) No. 141 and SFAS No. 142.

Overview

Our business primarily consists of interstate natural gas transmission, storage and terminalling operations. Our interstate natural gas transportation system, natural gas storage and LNG terminalling businesses face varying degrees of competition from other pipelines and proposed LNG facilities, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil.

The FERC regulates the rates we can charge our customers. These rates are a function of the costs of providing services to our customers, including a reasonable return on our invested capital. As a result, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as changes in natural gas prices and market conditions, regulatory actions, competition, weather and the creditworthiness of our customers. We also experience volatility in our financial results when the amounts of natural gas and electricity utilized in operations differ from the amounts we receive for those purposes. In 2004, 94 percent of our transportation services and storage revenues were attributable to reservation charges paid by firm customers. The remaining six percent was variable.

Our ability to extend existing customer contracts or remarket expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to recontract or remarket our capacity at the maximum rates allowed under our tariffs, although at times, we discount these rates to remain competitive. Our existing contracts mature at various times and in varying amounts of throughput capacity. We continue to manage our recontracting process to mitigate the risk of significant impacts on our revenues. The weighted average remaining contract term for active contracts is approximately five years as of December 31, 2004.

Below is the contract expiration portfolio for all contracts executed as of December 31, 2004, including those whose terms begin in 2005 or later. When these contracts are included, the portfolio has a weighted average remaining contract term of approximately 6.5 years.

	MDth/d	Percent of Total Contracted Capacity
2005	155	4
2006	592	17
2007	204	6
2008 and beyond	2,644	73

Results of Operations

Our management, as well as El Paso's management, uses earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business. We define EBIT as net income adjusted for (i) items that do not impact our income from continuing operations, (ii) income taxes, (iii) interest and debt expense and (iv) affiliated interest income. Our business consists of consolidated operations as well as investments in unconsolidated affiliates. We exclude interest and debt expense from this measure so that our management can evaluate our operating results without regard to our financing methods. We believe the discussion of our results of operations based on EBIT is useful to our investors because it allows them to more effectively evaluate the operating performance of both our consolidated business and our unconsolidated investments using the same performance measure analyzed internally by our management. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow.

The following is a reconciliation of EBIT to net income for the years ended December 31:

	2004	2003
	(In millions, except volume amounts)	
Operating revenues	$ 527	$ 482
Operating expenses	(281)	(253)
Operating income	246	229
Earnings from unconsolidated affiliates	78	55
Other income, net	9	11
Other	87	66
EBIT	333	295
Interest and debt expense	(94)	(87)
Affiliated interest income	4	4
Income taxes	(74)	(68)
Net income	$ 169	$ 144
Throughput volumes (BBtu/d)[(1)]	3,170	3,082

[(1)] Throughput volumes include volumes associated with proportionate share of our 50 percent equity interest in Citrus and billable transportation throughput volumes for storage injection.

The following items contributed to our overall EBIT increase of $38 million for the year ended December 31, 2004 as compared to 2003:

	Revenue	Expense	Other	EBIT Impact
	Favorable/(Unfavorable) (In millions)			
Mainline expansions	$33	$ (6)	$(6)	$21
Interruptible revenue	(3)	—	—	(3)
Gas not used in operations and other gas sales	10	(4)	—	6
Higher overhead allocation	—	(11)	—	(11)
Equity earnings from Citrus	—	—	22	22
Other	5	(7)	5	3
Total impact on EBIT	$45	$(28)	$21	$38

The following provides further discussions on some of the significant items listed above as well as events that may affect our operations in the future.

Mainline Expansions. Our mainline expansions consist of three major projects that were phased into service from June 2002 through August 2004. The increase in expansion revenue is offset by depreciation on the new facilities and the elimination of allowance for funds used during construction (AFUDC).

During the past two years, we have completed the following expansion projects that have generated new sources of revenues:

Project	Completion Date	Capacity Added
		(MMcf/d)
South System I	2002/2003	336
North System II	2003	33
South System II	2003/2004	330

Phase II of our South System II expansion project was placed in-service in 2004, at a total cost of approximately $256 million.

In April 2003, the FERC approved our expansion of our Elba Island LNG facility to increase the base load sendout rate of the facility from 446 MMcf/d to 806 MMcf/d. Our current cost estimates for the expansion are approximately $157 million, and expenditures as of December 31, 2004 were approximately $83 million. We commenced construction in July 2003 and expect to place the expansion in service in February 2006.

Citrus. Our EBIT increased due to earnings from our equity investment in Citrus. In 2004, Citrus exited its trading business, and as a result, incurred a favorable earnings impact.

Gas Not Used in Operations and Other Gas Sales. The financial impact of operational gas, net of gas used in operations is based on the amount of gas we are allowed to recover and dispose of according to the provisions in our tariff, relative to the amounts of gas we use for operating purposes, and the price of natural gas. The disposition of gas not needed for operations results in revenues to us, which are driven by volumes and prices during the period. During 2003 and 2004, we recovered, fairly consistently, volumes of natural gas that were not utilized for operations. These recoveries were and are based on factors such as system throughput, facility enhancements and the ability to operate the systems in the most efficient and safe manner. Additionally, a steadily increasing natural gas price environment during this timeframe also resulted in favorable impacts on our operating results in 2004 versus 2003. We anticipate that this area of our business will continue to vary in the future and will be impacted by the outcome of our ongoing rate case, including prospective changes in our tariff provisions governing recovery of operational gas and energy costs as well as the efficiency of our pipeline operations, the price of natural gas and other factors.

Regulatory Matters. In November 2004, the FERC issued a proposed accounting release that may impact certain costs we incur related to our pipeline integrity program. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact that this potential accounting release will have on our consolidated financial statements, we currently estimate that we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately $5 million to $7 million annually over the next eight years.

In November 2004, the FERC issued a Notice of Inquiry (NOI) seeking comments on its policy regarding selective discounting by natural gas pipelines. The FERC seeks comments regarding whether its practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons is appropriate when the discount is given to meet competition from another natural gas pipeline. We, along with several of our affiliated pipelines, filed comments on the NOI in March 2005. The final outcome of this inquiry cannot be predicted with certainty, nor can we predict the impact that the final rule will have on us.

We periodically file for changes in our rates which are subject to the approval of the FERC. In August 2004, we filed a rate case with the FERC seeking an annual rate increase of $35 million, or 11 percent in jurisdiction rates, no changes to cost allocation, rate design or current fuel retention percentage, and certain revisions to our effective tariff regarding terms and conditions of service. We have reached a tentative settlement in principle that will resolve all issues in this rate proceeding.

Interest and Debt Expense

Interest and debt expense for the year ended December 31, 2004, was $7 million higher than in 2003 primarily due to the issuance in March 2003 of $400 million senior unsecured notes with an annual interest rate of 8.875%.

Income Taxes

	Year Ended December 31, 2004	Year Ended December 31, 2003
	(In millions, except for rates)	
Income taxes	$74	$68
Effective tax rate	30%	32%

Our effective tax rates were different than the statutory rate of 35 percent in both periods primarily due to state income taxes offset by earnings from unconsolidated affiliates where we anticipate receiving dividends. For a reconciliation of the statutory rate to the effective rates, see Item 8, Financial Statements and Supplementary Data, Note 2.

Liquidity

Our liquidity needs have been provided by cash flows from operating activities and the use of El Paso's cash management program. Under El Paso's cash management program, depending on whether we have short-term cash surpluses or requirements, we either provide cash to El Paso or El Paso provides cash to us. We have historically provided cash advances to El Paso, and we reflect these advances as investing activities in our statement of cash flows. At December 31, 2004, we had a cash advance receivable from El Paso of $171 million as a result of this program. This receivable is due upon demand; however, we do not anticipate settlement within the next twelve months. At December 31, 2004, this receivable was classified as non-current notes receivable from affiliates on our balance sheet. We believe that cash flows from operating activities will be adequate to meet our short-term capital requirements for existing operations.

Capital Expenditures

Our capital expenditures for the years ended December 31 are as follows:

	2004	2003
	(In millions)	
Maintenance	$ 77	$ 54
Expansion/Other	122	183
Total	$199	$237

Under our current plan, we expect to spend between approximately $63 million and $69 million in each of the next three years for capital expenditures to maintain the integrity of our pipeline and ensure the safe and reliable delivery of natural gas to our customers. In addition, we have budgeted to spend between $80 million and $109 million in each of the next three years to expand the capacity and services of our system for long-term contracts. We expect to fund our maintenance and expansion capital expenditures through a combination of internally generated funds and/or by recovering some of the amounts advanced to El Paso under its cash management program. See Item 8, Financial Statements and Supplementary Data, Note 11 for a discussion of El Paso's cash management program.

In September 2004, we incurred significant damage to sections of our offshore pipeline facilities due to Hurricane Ivan. Total costs incurred for 2004 were approximately $11 million and our estimate for future costs are approximately $40 million. We expect insurance reimbursement for the cost of the damage with the exception of our share of a $2 million insurance deductible allocated from El Paso.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 7, which is incorporated herein by reference.

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2004, there were a number of accounting standards and interpretations that had been issued, but not yet adopted by us. Based on our assessment of those standards, we do not believe there are any that could have a material impact on us.

RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate," and similar expressions will generally identify forward-looking statements. Our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany those statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

With this in mind, you should consider the risks discussed elsewhere in this report and other documents we file with the Securities and Exchange Commission (SEC) from time to time and the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf.

Risks Related to Our Business

Our success depends on factors beyond our control.

Our business is primarily the transportation and storage of natural gas for third parties. As a result, the volume of natural gas involved in these activities depends on the actions of those third parties, and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current transmission and storage volumes and rates, to renegotiate existing contracts as they expire, or to remarket unsubscribed capacity:

- service area competition;
- expiration and/or turn back of significant contracts;
- changes in regulation and actions of regulatory bodies;
- future weather conditions;
- price competition;
- drilling activity and supply availability of natural gas;
- decreased availability of conventional gas supply sources and the availability and timing of other gas supply sources, such as LNG;
- increased availability or popularity of alternative energy sources such as hydroelectric power, coal and fuel oil;
- increased cost of capital;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions; and
- unfavorable movements in natural gas and liquids prices.

The revenues of our pipeline businesses are generated under contracts that must be renegotiated periodically.

Our revenues are generated under transportation services and storage contracts that expire periodically and must be renegotiated and extended or replaced. Although we actively pursue the renegotiation, extension and/or replacement of these contracts, we cannot assure that we will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts. Currently, our firm transportation capacity is fully subscribed through mid-2005 in our largest market areas, but could be renegotiated at rates below current rates upon the expiration of these contracts. For a further discussion of these matters, see Part I, Business — Markets and Competition.

In particular, our ability to extend and/or replace transportation services and storage contracts could be adversely affected by factors we cannot control, including:

- competition by other pipelines, including the proposed construction by other companies of additional pipeline capacity or LNG terminals in markets served by us;
- changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire;
- reduced demand and market conditions in the areas we serve;
- the availability of alternative energy sources or gas supply points; and
- regulatory actions.

If we are unable to renew, extend or replace these contracts or if we renew them on less favorable terms, we may suffer a material reduction in our revenues and earnings.

Fluctuations in energy commodity prices could adversely affect our business.

Revenues generated by our transportation services and storage contracts depend on volumes and rates, both of which can be affected by the prices of natural gas. Increased natural gas prices could result in a reduction of the volumes transported by our customers, such as power companies who, depending on the price of fuel, may not dispatch gas-fired power plants. Increased prices could also result in industrial plant shutdowns or load losses to competitive fuels and local distribution companies' loss of customer base. We also experience volatility in our financial results when the amounts of natural gas and electricity utilized in operations differ from the amounts we receive for those purposes. The success of our operations is subject to continued development of additional oil and natural gas reserves in the vicinity of our facilities and our ability to access additional suppliers from interconnecting pipelines, primarily in the Gulf of Mexico, to offset the natural decline from existing wells connected to our systems. A decline in energy prices could precipitate a decrease in these development activities and could cause a decrease in the volume of reserves available for transmission or storage on our system. If natural gas prices in the supply basins connected to our pipeline systems are higher than prices in other natural gas producing regions, our ability to compete with other transporters may be negatively impacted. Fluctuations in energy prices are caused by a number of factors, including:

- regional, domestic and international supply and demand;
- availability and adequacy of transportation facilities;
- energy legislation;
- federal and state taxes, if any, on the transportation and storage of natural gas and natural gas liquids;
- abundance of supplies of alternative energy sources; and
- political unrest among oil-producing countries.

The agencies that regulate us and our customers affect our profitability.

Our pipeline businesses are regulated by the FERC, the U.S. Department of Transportation and various state and local regulatory agencies. Our LNG terminalling business is also regulated by the U.S. Coast Guard. Regulatory actions taken by these agencies have the potential to adversely affect our profitability. In particular, the FERC regulates the rates we are permitted to charge our customers for our services. In setting authorized rates of return in a few recent FERC decisions, the FERC has utilized a proxy group of companies that includes local distribution companies that are not faced with as much competition or risk as interstate pipelines. The inclusion of these companies may create downward pressure on tariff rates when subjected to review at the FERC.

If our tariff rates were reduced in a future rate proceeding, if our volume of business under our currently permitted rates was decreased significantly or if we were required to substantially discount the rates for our services because of competition, our profitability and liquidity could be reduced.

Further, state agencies and local governments that regulate our local distribution company customers could impose requirements that could impact demand for our services.

Costs of environmental liabilities, regulations and litigation could exceed our estimates.

Our operations are subject to various environmental laws and regulations. These laws and regulations obligate us to install and maintain pollution controls and to clean up various sites at which regulated materials may have been disposed of or released. We are also party to legal proceedings involving environmental matters pending in various courts and agencies.

It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters because of:

- the uncertainties in estimating clean up costs;
- the discovery of new sites or information;
- the uncertainty in quantifying our liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the nature of environmental laws and regulations; and
- potential changes in environmental laws and regulations, including changes in the interpretation or enforcement thereof.

Although we believe we have established appropriate reserves for liabilities, including clean up costs, we could be required to set aside additional reserves in the future due to these uncertainties, and these amounts could be material. For additional information, see Item 8, Financial Statements and Supplementary Data, Note 7.

Our operations are subject to operational hazards and uninsured risks.

Our operations are subject to the inherent risks normally associated with pipeline operations, including pipeline ruptures, explosions, pollution, release of toxic substances, fires, adverse weather conditions, and other hazards, each of which could result in damage to or destruction of our facilities or damages or injuries to persons. In addition, our operations face possible risks associated with acts of aggression on our assets, which may include substantial periods to repair or replace our facilities and may include negative impacts on our revenue. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against many of these risks to the extent and in amounts that we believe are reasonable, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

Four customers contract for a majority of our firm transportation capacity.

For 2004, our contracts with Atlanta Gas Light Company, Southern Company Services, Alabama Gas Corporation and Scana Corporation represented approximately 27%, 12%, 12% and 10% of our firm transportation capacity. For additional information, see Part I, Item 1, Business — Markets and Competition and Item 8, Financial Statements and Supplementary Data, Note 9. The loss of one of these customers or a decline in its creditworthiness could adversely affect our results of operations, financial position and cash flow.

Risks Related to Our Affiliation with El Paso

El Paso files reports, proxy statements and other information with the SEC under the Securities Exchange Act of 1934, as amended. Each prospective investor should consider this information and the matters disclosed therein in addition to the matters described in this report. Such information is not incorporated by reference herein.

Our relationship with El Paso and its financial condition subjects us to potential risks that are beyond our control.

Due to our relationship with El Paso, adverse developments or announcements concerning El Paso could adversely affect our financial condition, even if we have not suffered any similar development. The ratings assigned to El Paso's senior unsecured indebtedness are below investment grade, currently rated Caa1 by Moody's Investor Service and CCC+ by Standard & Poor's. The ratings assigned to our senior unsecured indebtedness are currently rated B1 by Moody's Investor Service and B− by Standard & Poor's. Further downgrades of our credit ratings could increase our cost of capital and collateral requirements, and could impede our access to capital markets. El Paso continues its efforts to execute its Long-Range Plan that established certain financial and other objectives, including significant debt reduction. An inability to meet these objectives could adversely affect El Paso's liquidity position, and in turn affect our financial condition.

Pursuant to El Paso's cash management program, surplus cash is made available to El Paso in exchange for an affiliated receivable. In addition, we conduct commercial transactions with some of our affiliates. El Paso provides cash management and other corporate services for us. If El Paso is unable to meet its liquidity needs, there can be no assurance that we will be able to access cash under the cash management program, or that our affiliates would pay their obligations to us. However, we might still be required to satisfy affiliated company payables. Our inability to recover any affiliated receivables owed to us could adversely affect our ability to repay our outstanding indebtedness. For a further discussion of these matters, see Item 8, Financial Statements and Supplementary Data, Note 11.

In 2004, El Paso restated its 2003 and prior financial statements and the financial statements of certain of its subsidiaries for the same periods due to revisions to their natural gas and oil reserves and for adjustments related to the manner in which they historically accounted for hedges of their natural gas production. As a result of these reserve revisions, several class action lawsuits have been filed against El Paso and several of its subsidiaries, but not against us. The reserve revisions have also become the subject of investigations by the SEC and U.S. Attorney. These investigations and lawsuits may further negatively impact El Paso's credit ratings and place further demands on its liquidity.

We are required to maintain an effective system of internal control over financial reporting. As a result of our efforts to comply with this requirement, we determined that as of December 31, 2004, we did not maintain effective internal control over financial reporting. As more fully discussed in Item 9A, we identified several deficiencies in internal control over financial reporting, two of which management has concluded constituted material weaknesses. Although we have taken steps to remediate some of these deficiencies, additional steps must be taken to remediate the remaining control deficiencies. If we are unable to remediate our identified internal control deficiencies over financial reporting, or we identify additional deficiencies in our internal controls over financial reporting, we could be subjected to additional regulatory scrutiny, future delays in filing our financial statements and suffer a loss of public confidence in the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, which could have a negative impact on our liquidity, access to capital markets and our financial condition.

In addition to the risk of not completing the remediation of all deficiencies in our internal controls over financial reporting, we do not expect that our disclosure controls and procedures or our internal controls over financial reporting will prevent all mistakes, errors and fraud. Any system of internal controls, no matter how well designed or implemented, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The design of a control system must reflect the fact that the benefits of controls must be considered relative to their costs. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Therefore, any system of internal controls is subject to inherent limitations, including the possibility that controls may be circumvented or overridden, that judgments in decision-making can be faulty, and that misstatements due to mistakes, errors or fraud may occur and may not be detected. Also, while we document our assumptions and review financial disclosures, the regulations and literature governing our disclosures are complex and reasonable persons may disagree as to their application to a particular situation or set of facts. In addition, the applicable regulations and literature are relatively new. As a result, they are potentially subject to change in the future, which could include changes in the interpretation of the existing regulations and literature as well as the issuance of more detailed rules and procedures.

Our subsidiary may be subject to a change of control under certain circumstances.

Southern Gas Storage Company, our subsidiary, as well as our ownership in Bear Creek is pledged as collateral under El Paso's $3 billion credit agreement. As a result, their ownership is subject to change if there is an event of default under the credit agreement and El Paso's lenders under its credit agreement exercise rights over their collateral.

Furthermore, we have indentures governing our long-term debt that have cross-acceleration provisions with $10 million thresholds. If we have any debt in excess of $10 million accelerated for any reason, our long-term debt could be accelerated. The acceleration of our long-term debt could also adversely affect our liquidity positions and, in turn our financial condition.

We could be substantively consolidated with El Paso if El Paso were forced to seek protection from its creditors in bankruptcy.

If El Paso were the subject of voluntary or involuntary bankruptcy proceedings, El Paso and its other subsidiaries and their creditors could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of El Paso and its other subsidiaries. The equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities and to consolidate and pool the entities' assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. We believe that any effort to substantively consolidate us with El Paso and/or its other subsidiaries would be without merit. However, we cannot assure you that El Paso and/or its other subsidiaries or their respective creditors would not attempt to advance such claims in a bankruptcy proceeding or, if advanced, how a bankruptcy court would resolve the issue. If a bankruptcy court were to substantively consolidate us with El Paso and/or its other subsidiaries, there could be a material adverse effect on our financial condition and liquidity.

We are a wholly owned subsidiary of El Paso.

El Paso has substantial control over:

- our payment of dividends;
- decisions on our financings and our capital raising activities;
- mergers or other business combinations;
- our acquisitions or dispositions of assets; and
- our participation in El Paso's cash management program.

El Paso may exercise such control in its interests and not necessarily in the interests of us or the holders of our long-term debt.

Risks Related to Citrus Corp.

Florida Gas Transmission Company (FGT) depends substantially upon a small number of customers.

Upon completion of its current expansion, the five most significant customers on FGT's pipeline system will account for approximately 74% of contracted capacity, with the two most significant customers, Florida Power & Light Company and TECO Energy, Inc., including its subsidiaries Tampa Electric Company and Peoples Gas System, Inc., being obligated for approximately 39% and 21% of such capacity. Accordingly, failure of one or more of FGT's most significant customers to pay reservation charges could reduce its revenues materially and have a material adverse effect on its business, financial condition and results of operations.

Important actions by Citrus and FGT require approval by both CrossCountry Energy, LLC (CrossCountry) and us.

El Paso contributed its 50 percent interest in Citrus to us in March 2003. Effective April 2004, Enron Corp. (Enron), who owned the other 50 percent interest in Citrus, assigned its interest in Citrus to CrossCountry. Citrus' organizational documents and FGT's organizational documents require that "important matters" be approved by both CrossCountry and us. Important matters include the declaration of dividends and similar payments, the approval of operating budgets, the incurrence of indebtedness and the consummation of significant transactions. Consequently, we are dependent on CrossCountry's agreement to effect any such actions. CrossCountry's interests with respect to these important matters could be different from ours and, accordingly, we may be unable to cause Citrus and FGT to take important actions, such as the payment of dividends and the sale or acquisition of assets.

Citrus depends on CrossCountry entities to provide it with management and support services under an informal administrative services arrangement.

Various CrossCountry entities provide management and support services to Citrus and its subsidiaries, pursuant to an informal administrative services arrangement. These services include administration, legal, compliance and emergency services. The arrangement was originally governed by the provisions of an operating agreement between a CrossCountry affiliate and Citrus. The operating agreement expired on June 30, 2001 and has not been extended. However, the CrossCountry entities have continued to provide their services under an informal arrangement based on the provisions of the original operating agreement. Under the arrangement, Citrus and its subsidiaries reimburse the CrossCountry entities for costs attributable to the operations of Citrus and its subsidiaries.

Although we believe that the CrossCountry entities will continue to perform management and support services for Citrus and its subsidiaries, and that Citrus could obtain such services from other sources in a timely and cost effective manner, Citrus may be unable to obtain such services from other sources on terms favorable to Citrus in the event the CrossCountry entities stop providing them. Failure to obtain management and support services in a timely and cost effective manner could have a material adverse effect on Citrus' business.

Ongoing litigation regarding Citrus Trading Corporation (CTC) could adversely affect our business.

In March 2003, CTC filed suit against Duke Energy LNG Sales, Inc. (Duke) seeking damages for breach of a gas supply contract under which CTC was entitled to purchase regasified liquefied natural gas. In April 2003, Duke forwarded a letter to CTC purporting to terminate the contract due to the alleged failure of CTC to increase the amount of an outstanding letter of credit backstopping its purchase obligations. On May 1, 2003, CTC notified Duke that Duke was in default under the contract. CTC subsequently filed an amended complaint, alleging wrongful contract termination and specifying damages of $185 million. At this time, the outcome of this litigation is not determinable. For further discussion of these matters, see Item 8, Financial Statements and Supplementary Data, Note 7.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our primary market risk is exposure to changing interest rates. The table below shows the carrying value and related weighted average effective interest rates of our interest bearing securities, by expected maturity dates, and the fair value of those securities. At December 31, 2004, the fair values of our fixed rate long-term debt securities have been estimated based on quoted market prices for the same or similar issues.

	December 31, 2004					December 31, 2003	
	Expected Fiscal Year of Maturity of Carrying Amounts						
	2007	2008	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
				(In millions)			
Liabilities:							
Long-term debt, including							
current portion — fixed rate	$100	$100	$995	$1,195	$ 1,302	$1,194	$1,259
Average interest rate	6.8%	6.3%	8.3%				

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

SOUTHERN NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2004	2003	2002 (Restated)
Operating revenues	$527	$482	$429
Operating expenses			
Operation and maintenance	206	185	162
Depreciation, depletion and amortization	50	47	45
Taxes, other than income taxes	25	21	20
	281	253	227
Operating income	246	229	202
Earnings from unconsolidated affiliates	78	55	55
Other income, net	9	11	9
Interest and debt expense	(94)	(87)	(57)
Affiliated interest income	4	4	8
Income before income taxes	243	212	217
Income taxes	74	68	67
Net income	$169	$144	$150
Other comprehensive loss	—	—	(5)
Comprehensive Income	$169	$144	$145

See accompanying notes.

SOUTHERN NATURAL GAS COMPANY

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2004	December 31, 2003 (Restated)
ASSETS		
Current assets		
Cash and cash equivalents	$ —	$ —
Accounts and notes receivable		
Customer, net of allowance of $3 in 2004 and 2003	80	83
Other	—	1
Materials and supplies	11	12
Other	19	12
Total current assets	110	108
Property, plant and equipment, at cost	3,234	3,055
Less accumulated depreciation, depletion and amortization	1,344	1,326
Total property, plant and equipment, net	1,890	1,729
Other assets		
Investments in unconsolidated affiliates	740	731
Notes receivable from affiliates	171	153
Regulatory assets	41	35
Other	11	17
	963	936
Total assets	$2,963	$2,773
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 36	$ 34
Affiliates	8	8
Other	2	1
Taxes payable	58	59
Accrued interest	30	30
Contractual deposits	3	13
Other	3	5
Total current liabilities	140	150
Long-term debt	1,195	1,194
Other liabilities		
Deferred income taxes	296	266
Other	54	54
	350	320
Commitments and contingencies		
Stockholder's equity		
Common stock, par value $1 per share; 1,000 shares authorized, issued and outstanding	—	—
Additional paid-in capital	340	340
Retained earnings	946	777
Accumulated other comprehensive loss	(8)	(8)
Total stockholder's equity	1,278	1,109
Total liabilities and stockholder's equity	$2,963	$2,773

See accompanying notes.

SOUTHERN NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2004	2003	2002 (Restated)[1]
Cash flows from operating activities			
Net income	$169	$ 144	$ 150
Adjustments to reconcile net income to net cash from operating activities			
Depreciation, depletion and amortization	50	47	45
Deferred income tax expense	26	31	44
Earnings from unconsolidated affiliates, adjusted for cash distributions	(8)	(54)	(55)
Other non-cash income items	(3)	—	3
Asset and liability changes			
Accounts and notes receivable	3	(10)	(1)
Accounts payable	3	(4)	—
Taxes payable	—	11	(2)
Other asset and liability changes			
Assets	(12)	(8)	21
Liabilities	(11)	10	4
Net cash provided by operating activities	217	167	209
Cash flows from investing activities			
Additions to property, plant and equipment	(199)	(237)	(250)
Net change in affiliated advances	(18)	(33)	(59)
Other	—	9	3
Net cash used in investing activities	(217)	(261)	(306)
Cash flows from financing activities			
Payments to retire long-term debt	—	—	(200)
Net proceeds from the issuance of long-term debt	—	384	297
Dividends paid	—	(290)	—
Net cash provided by financing activities	—	94	97
Net change in cash and cash equivalents	—	—	—
Cash and cash equivalents			
Beginning of period	—	—	—
End of period	$ —	$ —	$ —

(1) Only individual line items in cash flows from operating activities have been restated. Total cash flows from operating activities, investing activities and financing activities were unaffected by our restatement.

See accompanying notes.

SOUTHERN NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY
(In millions, except share amounts)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
	Shares	Amount				
January 1, 2002	1,000	$ —	$340	$1,083	$ (3)	$1,420
Net income (Restated)				150		150
Allocated tax benefit of El Paso equity plans			1			1
Other comprehensive loss					(5)	(5)
December 31, 2002 (Restated)	1,000	—	341	1,233	(8)	1,566
Net income				144		144
Allocated tax expense of El Paso equity plans			(1)			(1)
Dividends				(600)		(600)
December 31, 2003 (Restated)	1,000	—	340	777	(8)	1,109
Net income				169		169
December 31, 2004	1,000	$ —	$340	$ 946	$ (8)	$1,278

See accompanying notes.

SOUTHERN NATURAL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned and controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications had no impact on reported net income or stockholder's equity.

Restatement

During the completion of the financial statements for the year ended December 31, 2004, we identified an error in the manner in which we had originally adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations* and SFAS No. 142, *Goodwill and Other Intangible Assets,* in 2002. Upon adoption of these standards, we incorrectly adjusted the cost of investments in unconsolidated affiliates and recorded a cumulative effect of a change in accounting principle for the excess of our share of the affiliates' fair value of net assets over their original cost, which we believed was negative goodwill. The amount originally recorded as a cumulative effect of an accounting change was $57 million and related to our investment in Citrus. We subsequently determined that the amount we adjusted was not negative goodwill, but rather an amount that should have been allocated to the long-lived assets underlying our investment. As a result, we restated our 2002 financial statements to reverse the amount we recorded as a cumulative effect of an accounting change on January 1, 2002. This adjustment also impacted a related deferred tax adjustment we recorded during 2002. The restatement also affected the investment, deferred tax liability and stockholders' equity balances we reported as of December 31, 2002 and 2003. Below are the effects of our restatement.

	Year Ended December 31, 2002	
	As Reported	As Restated
	(In millions)	
Income Statement:		
Income taxes	$ 87	$ 67
Cumulative effect of accounting changes, net of income taxes	57	—
Net income	187	150

	As of December 31, 2003		As of December 31, 2002	
	As Reported	As Restated	As Reported	As Restated
Balance Sheet:				
Investments in unconsolidated affiliates	$ 788	$ 731	$ 734	$ 677
Non-current deferred income tax liabilities	286	266	260	240
Stockholder's equity	1,146	1,109	1,603	1,566

The restatement did not impact 2003 and 2004 reported income amounts except that we recorded an adjustment related to these periods of $4 million in the fourth quarter of 2004. Other than the effects above, the components of this restatement were immaterial to all previously reported interim and annual periods.

Principles of Consolidation

We consolidate entities when we either (i) have the ability to control the operating and financial decisions and policies of that entity or (ii) are allocated a majority of the entity's losses and/or returns through our variable interest in that entity. The determination of our ability to control or exert significant influence over an entity and whether we are allocated a majority of the entity's losses and/or returns involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control, the policies and decisions of an entity and where we are not allocated a majority of the entity's losses and/or returns. We use the cost method of accounting where we are unable to exert significant influence over the entity.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Regulated Operations

Our natural gas systems and storage operations are subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, and we currently apply the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.* We perform an annual study to assess the ongoing applicability of SFAS No. 71. The accounting required by SFAS No. 71 differs from the accounting required for businesses that do not apply its provisions. Transactions that are generally recorded differently as a result of applying regulatory accounting requirements include capitalizing an equity return component on regulated capital projects, postretirement employee benefit plans, and other costs included in, or expected to be included in, future rates.

Cash and Cash Equivalents

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of an outstanding receivable balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

Materials and Supplies

We value materials and supplies at the lower of cost or market value with cost determined using the average cost method.

Natural Gas Imbalances

Natural gas imbalances generally occur when the actual amount of natural gas received on a customer's contract at the supply point differs from the actual amount of natural gas delivered under the customer's transportation contract at the delivery point. We value imbalances due to or from shippers at specified index prices set forth in our tariff based on the production month in which the imbalances occur. Customer imbalances are aggregated and netted (by customer) on a monthly basis, and settled in cash, subject to the terms of our tariff. For differences in value between the amounts we pay or receive for the purchase or sale of gas used to resolve shipper imbalances over the course of a year, we have the right under our tariff to recover applicable losses through a storage cost reconciliation charge. This charge is applied to all volumes transported on our system. We are obligated annually to true-up any losses or gains obtained during the course of each year in calculating the following years' storage cost reconciliation charge.

Imbalances due from others are reported in our balance sheet as either accounts receivable from customers or accounts receivable from affiliates. Imbalances owed to others are reported on the balance sheet as either trade accounts payable or accounts payable to affiliates. In addition, we classify all imbalances as current.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in service. For assets we construct, we capitalize direct costs, such as labor and materials and indirect costs, such as overhead, interest and an equity return component for our regulated businesses as allowed by the FERC. We capitalize the major units of property replacements or improvements and expense minor items.

We use the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the FERC-accepted depreciation rate to the total cost of the group until its net book value equals its salvage value. Currently, our depreciation rates vary from one to 20 percent. Using these rates, the remaining depreciable lives of these assets range from one to 57 years. We re-evaluate depreciation rates each time we file with the FERC for a change in our transportation and storage service rates.

When we retire property, plant and equipment, we charge accumulated depreciation and amortization for the original cost, plus the cost to remove, sell or dispose, less its salvage value. We do not recognize a gain or loss unless we sell an entire operating unit. We include gains or losses on dispositions of operating units in income.

At December 31, 2004 and 2003, we had approximately $129 million and $81 million of construction work in progress included in our property, plant and equipment.

We capitalize a carrying cost or AFUDC on funds invested in our construction of long-lived assets. This carrying cost consists of a return on the investment financed by debt and a return on the investment financed by equity. The debt portion is calculated based on our average cost of debt. Debt amounts capitalized during the years ended December 31, 2004, 2003 and 2002, were $3 million, $3 million and $2 million. These amounts are included as a reduction to interest expense in our income statement. The equity portion is calculated using the most recent FERC approved equity rate of return. The equity amounts capitalized during the years ended December 31, 2004, 2003 and 2002 were $6 million, $7 million and $5 million (exclusive of any tax related impacts). These amounts are included as other non-operating income on our income statement. Capitalized carrying costs for debt and equity financed construction are reflected as an increase in the cost of the asset on our balance sheet.

Asset and Investment Impairments

We apply the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* and Accounting Principles Board Opinion No. 18, *The Equity Method of Accounting for Investments in Common Stock,* to account for asset and investment impairments. Under these standards, we evaluate an asset or investment for impairment when events or circumstances indicate that its carrying value may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset and adverse changes in the legal or business environment such as adverse actions by regulators. When an event occurs, we evaluate the recoverability of our carrying value based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of our investment in unconsolidated affiliates. If an impairment is indicated or if we decide to exit or sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to their estimated fair value, less costs to sell. Our fair value estimates are generally based on market data obtained through the sales process or an analysis of expected discounted cash flows. The magnitude of any impairment is impacted by a number of factors, including the nature of the assets to be sold and our established time frame for completing the sales, among other factors.

Revenue Recognition

Our revenues are generated from transportation and storage services and operational sales of natural gas. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity over the contract period regardless of the amount of natural gas that is transported or stored. For interruptible or volumetric based transportation services, as well as revenues on operational sales of natural gas and related products, we record revenues when physical deliveries of natural gas and other commodities are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage facility. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. We are subject to FERC regulations and, as a result, revenues we collect may possibly be refunded in a final order of a pending rate proceeding or as a result of a rate settlement. We establish reserves for these potential refunds.

Price Risk Management Activities

Our equity investee, Citrus, uses derivatives to mitigate, or hedge, cash flow risk associated with its variable interest rates on long-term debt. Citrus accounts for these derivatives under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and records changes in the fair value of these derivatives in other comprehensive income. We reflect our proportionate share of the impact these derivative instruments have on Citrus' financial statements as adjustments to our other comprehensive income and our investment in unconsolidated affiliates.

Environmental Costs and Other Contingencies

We record environmental liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. We recognize a current period expense for the liability when the clean-up efforts do not benefit future periods. We capitalize costs that benefit more than one accounting period, except in instances where separate agreements or legal and regulatory guidelines dictate otherwise. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into account the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage, rate recovery, government sponsored and other programs separately from our liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Income Taxes

El Paso maintains a tax accrual policy to record both regular and alternative minimum taxes for companies included in its consolidated federal and state income tax returns. The policy provides, among other things, that (i) each company in a taxable income position will accrue a current expense equivalent to its federal and state income taxes, and (ii) each company in a tax loss position will accrue a benefit to the extent its deductions, including general business credits, can be utilized in the consolidated returns. El Paso pays all consolidated U.S. federal and state income taxes directly to the appropriate taxing jurisdictions and, under a separate tax billing agreement, El Paso may bill or refund its subsidiaries for their portion of these income tax payments.

Pursuant to El Paso's policy, we report current income taxes based on our taxable income and we provide for deferred income taxes to reflect estimated future tax payments or receipts. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in the recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

2. Income Taxes

The following table reflects the components of income taxes included in net income for each of the three years ended December 31:

	2004	2003	2002 (Restated)
		(In millions)	
Current			
Federal	$42	$31	$20
State	6	6	3
	48	37	23
Deferred			
Federal	22	28	41
State	4	3	3
	26	31	44
Total income taxes	$74	$68	$67

Our income taxes differ from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

	2004	2003	2002 (Restated)
		(In millions)	
Income taxes at the statutory federal rate of 35%	$ 85	$ 74	$76
Increase (decrease)			
State income taxes, net of federal income tax benefit	6	6	4
Earnings from unconsolidated affiliates where we anticipate receiving dividends	(17)	(12)	(13)
Income taxes	$ 74	$ 68	$67
Effective tax rate	30%	32%	31%

The following are the components of our net deferred tax liability at December 31:

	2004	2003 (Restated)
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$265	$255
Regulatory assets	10	10
Investment in unconsolidated affiliates	28	23
Materials and supplies	13	11
Other	22	23
Total deferred tax liability	338	322
Deferred tax assets		
Accrual for regulatory issues	10	24
Employee benefit and deferred compensation obligations	13	11
U.S. net operating loss and tax credit carryovers	7	7
Other	17	17
Valuation allowance	(1)	(1)
Total deferred tax asset	46	58
Net deferred tax liability	$292	$264

Under El Paso's tax accrual policy, we are allocated the tax effects associated with our employees' non-qualified dispositions of employee stock purchase plan stock, the exercise of non-qualified stock options and the vesting of restricted stock as well as restricted stock dividends. This allocation did not have a material effect in 2004; however, it increased taxes payable by $1 million in 2003 and reduced taxes payable by $1 million in 2002. These tax effects are included in additional paid-in capital in our balance sheet.

The following are the components of our carryovers as of December 31, 2004:

Carryover	Amount	Expiration Date
	(In millions)	
General business credit	$ 1	2016-2017
Charitable contributions	1	2008
Net operating loss[1]	16	2018-2021

[1] $14 million of this amount expires in 2018, $1 million in 2019 and $1 million in 2021.

Usage of these carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations. We have recorded a valuation allowance to reserve for the deferred taxes related to our general business credits.

3. Financial Instruments

The carrying amounts and estimated fair values of our financial instruments are as follows at December 31:

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Balance sheet financial instruments:				
Long-term debt[1]	$1,195	$1,302	$1,194	$1,259

[1] We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues.

At December 31, 2004 and 2003, the carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term maturity of these instruments.

4. Regulatory Assets and Liabilities

Below are the details of our regulatory assets and liabilities at December 31:

Description	2004	2003
	(In millions)	
Non-current regulatory assets		
Deferred taxes on capitalized funds used during construction	$38	$35
Other	3	—
Total non-current regulatory assets[1][2]	$41	$35
Non-current regulatory liabilities		
Cost of removal of offshore assets	$18	$17
Excess deferred federal income taxes	2	2
Total non-current regulatory liabilities[2]	$20	$19

(1) These amounts are not included in our rate base on which we earn a current return.

(2) Amounts are included as other non-current assets and liabilities in our balance sheet.

5. Accounting for Hedging Activities

As of December 31, 2004 and 2003, our equity interest in the value of Citrus' cash flow hedges included in accumulated other comprehensive loss was an unrealized loss of $8 million, net of income taxes. This amount will be reclassified to earnings over the terms of Citrus' outstanding debt. We estimate that less than $1 million of this unrealized loss will be reclassified from accumulated other comprehensive loss over the next twelve months. For the years ended December 31, 2004, 2003 and 2002, no ineffectiveness was recorded in earnings on these cash flow hedges.

6. Debt and Other Credit Facilities

Our long-term debt outstanding consisted of the following at December 31:

	2004	2003
	(In millions)	
6.70% Notes due 2007	$ 100	$ 100
6.125% Notes due 2008	100	100
8.875% Notes due 2010	400	400
7.35% Notes due 2031	300	300
8.0% Notes due 2032	300	300
	1,200	1,200
Less: Unamortized discount	5	6
Long-term debt	$1,195	$1,194

Aggregate maturities of the principal amounts of long-term debt for the next 5 years and in total thereafter are as follows:

Year	(In millions)
2007	$ 100
2008	100
Thereafter	1,000
Total maturities of long-term debt	$1,200

In March 2003, we issued $400 million of unsecured senior notes with an annual interest rate of 8.875%. The notes mature in 2010. Net proceeds were used to pay a cash dividend to our parent of approximately $290 million, while the remaining proceeds were used for capital expenditures in 2003.

Credit Facilities

In November 2004, El Paso replaced its previous $3 billion revolving credit facility with a new $3 billion credit agreement with a group of lenders. The credit agreement consists of a $1.25 billion term loan facility, a $750 million letter of credit facility, and a $1 billion revolving credit facility. The letter of credit facility provides El Paso the ability to issue letters of credit or borrow any unused capacity as revolving loans. At December 31, 2004, El Paso had $1.25 billion outstanding under the term loan facility and utilized approximately all of the $750 million letter of credit facility and approximately $0.4 billion of the $1 billion revolving credit facility to issue letters of credit. We are not a borrower under El Paso's credit agreement; however, El Paso's interest in our subsidiary, Southern Gas Storage Company, as well as our interest in Bear Creek, are pledged as collateral under the new credit agreement.

Under our indentures, we are subject to a number of restrictions and covenants. The most restrictive of these include (i) limitations on the incurrence of additional debt, based on a ratio of debt to EBITDA (as defined in the agreements), the most restrictive of which shall not exceed 6 to 1; (ii) limitations on the use of proceeds from borrowings; (iii) limitations, in some cases, on transactions with our affiliates; (iv) limitations on the incurrence of liens; (v) potential limitations on our ability to declare and pay dividends; and (vi) potential limitations on our ability to participate in El Paso's cash management program discussed in Note 11. For the year ended December 31, 2004, we were in compliance with all of our debt-related covenants.

7. Commitments and Contingencies

Legal Proceedings

Grynberg. In 1997, we and a number of our affiliates were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). Motions to dismiss have been filed on behalf of all defendants. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Royalty Claim. In five contract settlements reached in the late 1980s with Elf Aquitaine (Elf) pertaining to the pricing of gas produced from certain federal offshore blocks, we indemnified Elf against royalty claims that potentially could have been asserted by the Minerals Management Service (MMS). Following its settlements with us, Elf received demands from MMS for royalty payments related to the settlements. With our approval, Elf protested the demands for over a decade while trying to reach a settlement with the MMS. Elf, which is now TOTAL E&P USA (TOTAL), advised us that it had renewed efforts to settle claims by the MMS for excess royalties attributable to price reductions that we achieved in the gas contract settlements in the late 1980s. TOTAL informed us that the MMS is claiming in excess of $13 million in royalties, a large portion of which is interest, for the five settlements with us. We have advised TOTAL that not all of the amounts being sought by the MMS are covered by our indemnity. If TOTAL cannot resolve these claims administratively with MMS, then an appeal can be taken to the federal courts. We have the right under a pre-existing settlement with our customers to recover through a surcharge payable by our customers a portion of the amount ultimately paid under the royalty indemnity with TOTAL.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate. At December 31, 2004, we had accrued approximately $2 million for our outstanding legal matters.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. At December 31, 2004, we had accrued less than $1 million for expected remediation costs and associated onsite, offsite and groundwater technical studies, which we anticipate incurring through 2027. Our accrual was based on the most likely outcome that can be reasonably estimated. Below is a reconciliation of our accrued liability at December 31, 2004 (in millions):

Balance at January 1, 2004	$ 3
Additions/adjustments for remediation activities	1
Payments for remediation activities	(4)
Balance at December 31, 2004	$—

In addition, we expect to make capital expenditures for environmental matters of approximately $4 million in the aggregate for the years 2005 through 2009. These expenditures primarily relate to compliance with clean air regulations. For 2005, we estimate that our total remediation expenditures will be less than $1 million, which will be expended under government directed clean-up plans.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

Rates and Regulatory Matters

Rate Case. In August 2004, we filed a rate case with the FERC seeking an annual rate increase of $35 million, or 11 percent in jurisdictional rates, no changes to cost allocation, rate design or current fuel retention percentage, and certain revisions to our effective tariff regarding terms and conditions of service. In September 2004, the FERC issued a suspension order accepting certain proposed tariff revisions, including the elimination of right of first refusal matching term limitations, changes in the imbalance cash-out price calculations, and permitting formularized discounting as a non-material deviation. These revisions became effective in October 2004. The order established a technical conference to assess other proposed tariff revisions, including notice to exercise public service commission (PSC) outs, restrictions on firm receipt point amendments, the application of the storage reconciliation mechanism surcharge (SCRM) to additional services on our system, and the change in cash-out pricing for imbalances of less than 2 percent. The FERC established a hearing, which is scheduled for July 2005, on our proposed rate increase, to become effective in March 2005, subject to refund and conditions. On December 9, 2004, the FERC staff convened a technical conference on tariff issues not set for hearing. On February 28, 2005, the FERC issued an order on Technical Conference and Rehearing accepting all tariff changes proposed by us in our rate filing except for one proposal governing changes to receipt points under existing service agreements, which was set for hearing. We have reached a tentative settlement in principle that will resolve all issues in our rate proceeding.

Rate Investigation. In December 2004, SLNG filed a cost and revenue study with the FERC, in compliance with existing certificate authorization, to justify its existing rates for terminaling service at its LNG marine receiving terminal at Elba Island. In February 2005, the FERC set the cost and revenue study for hearing under Section 5 of the Natural Gas Act to determine if the current rates remain just and reasonable.

Accounting for Pipeline Integrity Costs. In November 2004, the FERC issued a proposed accounting release that may impact certain costs we incur related to our pipeline integrity program. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact that this potential accounting release will have on our consolidated financial statements, we currently estimate that we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately $5 million to $7 million annually over the next eight years.

Inquiry Regarding Income Tax Allowances. In December 2004, the FERC issued a Notice of Inquiry (NOI) in response to a recent D.C. Circuit decision that held the FERC had not adequately justified its policy of providing a certain oil pipeline limited partnership with an income tax allowance equal to the proportion of its limited partnership interests owned by corporate partners. The FERC sought comments on whether the court's reasoning should be applied to other partnerships or other ownership structures. We own interests in non-taxable entities that could be affected by this ruling. We cannot predict what impact this inquiry will have on our interstate pipelines.

Selective Discounting Notice of Inquiry. In November 2004, the FERC issued a NOI seeking comments on its policy regarding selective discounting by natural gas pipelines. The FERC seeks comments regarding whether its practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons is appropriate when the discount is given to meet competition from another natural gas pipeline. We, along with several of our affiliated pipelines, filed comments on the NOI in March 2005. The final outcome of this inquiry cannot be predicted with certainty, nor can we predict the impact that the final rule will have on us.

While the outcome of our outstanding rates and regulatory matters cannot be predicted with certainty, based on current information, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters.

Other Matters

Atlanta Gas Light. The majority of our contracts for firm transportation service with our largest customer, Atlanta Gas Light Company (AGL), were due to expire in 2005. In April 2004, we and AGL executed definitive agreements pursuant to which AGL agreed to extend its firm transportation service contracts with us for 926,534 Mcf/d for a weighted average term of 6.5 years between 2008 and 2015 in exchange for the sale by us to AGL of approximately 250 miles of certain pipeline facilities and nine measurement facilities in the metropolitan Atlanta area at a transfer price now estimated at approximately $31 million. Such agreements to implement the transactions (Triangle Project) were made subject to approvals by the FERC and the Georgia Public Service Commission (GPSC). The FERC and GPSC issued orders generally approving the Triangle Project on January 25, 2005 and November 2, 2004, respectively. Closing of the transaction was held on March 1, 2005, and construction of the 6.36 miles of pipeline to close the gap between the two segments on our 30-inch Ocmulgee-Atlanta Line is scheduled to begin in March 2005.

Duke Litigation. CTC, a direct subsidiary of Citrus, has filed suit against Duke Energy LNG Sales, Inc (Duke) and PanEnergy Corp., the holding company of Duke, seeking damages of $185 million for breach of a gas supply contract and wrongful termination of that contract. Duke sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit as collateral for its purchase obligations. Duke has filed in federal court an amended counter claim joining Citrus and a cross motion for partial summary judgment, requesting that the court find that Duke had a right to terminate its gas sales contract with CTC due to the failure of CTC to adjust the amount of the letter of credit supporting its purchase obligations. CTC filed an answer to Duke's motion, which is currently pending before the court. An adverse outcome on these matters could impact our investment in Citrus. We do not expect the ultimate resolution of this matter to have a material adverse effect on us.

While the outcome of these matters cannot be predicted with certainty, based on current information and our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our financial position, operating results or cash flows. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters, and adjust our accruals accordingly. The impact of these changes may have a material effect on our results of operations, our financial position, and our cash flows in the periods these events occur.

Capital Commitments and Purchase Obligations

At December 31, 2004, we had capital and investment commitments of $73 million primarily relating to the expansion of our Elba Island facility. Our other planned capital and investment projects are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures. In addition, we have entered into unconditional purchase obligations for products and services totaling $34 million at December 31, 2004. Our annual obligations under these agreements are $19 million for 2005, $11 million for 2006, $1 million for 2007, $2 million for 2008 and $1 million for 2009.

Operating Leases

We lease property, facilities and equipment under various operating leases. The majority of our total commitments on operating leases is the lease of the AmSouth Center located in Birmingham, Alabama. El Paso guarantees all obligations under this lease agreement. Minimum future annual rental commitments on our operating leases as of December 31, 2004, were as follows:

Year Ending December 31,	Operating Leases
	(In millions)
2005	$ 2
2006	2
2007	3
2008	3
Total	$10

Rental expense on our operating leases for each of the years ended December 31, 2004, 2003, and 2002 was $3 million, $3 million and $4 million.

8. Retirement Benefits

Pension and Retirement Benefits

El Paso maintains a pension plan to provide benefits determined under a cash balance formula covering substantially all of its U.S. employees, including our employees. Prior to January 1, 2000, Sonat Inc., our former parent company, maintained a pension plan for our employees. On January 1, 2000, the Sonat pension plan was merged into El Paso's cash balance plan. Our employees who were active participants in the Sonat pension plan on December 31, 1999, receive the greater of cash balance benefits under the El Paso plan or Sonat plan benefits accrued through December 31, 2004.

El Paso also maintains a defined contribution plan covering its U.S. employees, including our employees. Prior to May 1, 2002, El Paso matched 75 percent of participant basic contributions up to 6 percent, with the matching contributions being made to the plan's stock fund, which participants could diversify at any time. After May 1, 2002, the plan was amended to allow for company matching contributions to be invested in the same manner as that of participant contributions. Effective March 1, 2003, El Paso suspended the matching contributions, but reinstituted it again at a rate of 50 percent of participant basic contributions up to 6 percent on July 1, 2003. Effective July 1, 2004, El Paso increased the matching contributions to 75 percent of participant basic contributions up to 6 percent. El Paso is responsible for benefits accrued under its plans and allocates the related costs to its affiliates.

Other Postretirement Benefits

As a result of our merger with El Paso in October 1999, we offered a one-time election through an early retirement window for Sonat employees who were at least age 50 with 10 years of service on December 31, 1999, to retire on or before June 30, 2000, and keep benefits under Sonat's past retirement medical and life plans. Medical benefits for this closed group of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs. El Paso reserves the right to change these benefits. Employees who retire after June 30, 2000, continue to receive limited postretirement life insurance benefits. Our postretirement benefit plan costs are prefunded to the extent these costs are recoverable through our rates. We expect to contribute $4 million to our other postretirement benefit plan in 2005.

In 2004, we adopted FASB Staff Position (FSP) No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.* This pronouncement required us to record the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 on our postretirement benefit plans that provide drug benefits that are covered by that legislation. The adoption of FSP No. 106-2 decreased our accumulated postretirement benefit obligation by $17 million, which is deferred as an actuarial gain in our postretirement benefit liabilities as of December 31, 2004. We expect that the adoption of this guidance will reduce our postretirement benefit expense by approximately $2 million in 2005.

The following table presents the change in projected benefit obligation, change in plan assets and reconciliation of funded status for our other postretirement benefit plan. Our benefits are presented and computed as of and for the twelve months ended September 30 (the plan reporting date):

	2004	2003
	(In millions)	
Change in benefit obligation:		
Projected benefit obligation at beginning of period	$108	$ 81
Interest cost	6	5
Participant contributions	1	1
Actuarial (gain) loss	(21)	27
Benefits paid	(5)	(6)
Projected benefit obligation at end of period	$ 89	$108
Change in plan assets:		
Fair value of plan assets at beginning of period	$ 51	$ 45
Actual return on plan assets	2	7
Employer contributions	4	4
Participant contributions	1	1
Benefits paid	(5)	(6)
Fair value of plan assets at end of period	$ 53	$ 51
Reconciliation of funded status:		
Under funded status as of September 30	$(36)	$(57)
Unrecognized actuarial loss	12	34
Net accrued benefit cost at December 31	$(24)	$(23)

Future benefits expected to be paid on our other postretirement plan as of December 31, 2004, are as follows (in millions):

Year Ending December 31,	
2005	$ 7
2006	6
2007	7
2008	7
2009	7
2010 – 2014	32
Total	$66

Our postretirement benefit costs recorded in operating expenses include the following components for the years ended December 31:

	2004	2003	2002
		(In millions)	
Interest cost	$ 6	$ 5	$ 6
Expected return on plan assets	(3)	(2)	(2)
Amortization of actuarial loss	2	—	—
Net postretirement benefit cost	$ 5	$ 3	$ 4

Projected benefit obligations and net benefit costs are based on actuarial estimates and assumptions. The following table details the weighted average actuarial assumptions used for our other postretirement plan for 2004, 2003 and 2002:

	2004	2003	2002
		(Percent)	
Assumptions related to benefit obligations at September 30:			
Discount rate	5.75	6.00	
Assumptions related to benefit costs at December 31:			
Discount rate	6.00	6.75	7.25
Expected return on plan assets(1)	7.50	7.50	7.50

(1) The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 29 percent to 32 percent on postretirement benefits) that is primarily based on an expected risk-free investment return, adjusted for historical risk premiums and specific risk adjustments associated with our debt and equity securities. These expected returns were then weighted based on the target asset allocations of our investment portfolio.

Actuarial estimates for our postretirement benefits plan assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 10.0 percent in 2004, gradually decreasing to 5.5 percent by the year 2009. Assumed health care cost trends can have a significant effect on the amounts reported for other postretirement benefit plan. A one-percentage point change in our assumed health care cost trends would have the following effects as of September 30:

	2004	2003
	(In millions)	
One percentage point increase:		
Aggregate of service cost and interest cost	$—	$—
Accumulated postretirement benefit obligation	$ 7	$ 7
One percentage point decrease:		
Aggregate of service cost and interest cost	$—	$—
Accumulated postretirement benefit obligation	$(6)	$(6)

Other Postretirement Plan Assets

The following table provides the actual asset allocations in our postretirement plan as of September 30:

Asset Category	Actual 2004	Actual 2003
	(Percent)	
Equity securities	62	29
Debt securities	34	62
Other	4	9
Total	100	100

The primary investment objective of our plan is to ensure, that over the long-term life of the plan, an adequate pool of sufficiently liquid assets exists to support the benefit obligation to participants, retirees and beneficiaries. In meeting this objective, the plan seeks to achieve a high level of investment return consistent with a prudent level of portfolio risk. Investment objectives are long-term in nature covering typical market cycles of three to five years. Any shortfall in investment performance compared to investment objectives is the result of general economic and capital market conditions.

The target allocation for the invested assets is 65 percent equity and 35 percent fixed income. In 2003, we modified our target asset allocations for our postretirement benefit plan to increase our equity allocation to 65 percent of total plan assets. Other assets are held in cash for payment of benefits upon presentment. Any El Paso stock held by the plan is held indirectly through investments in mutual funds.

9. Transactions with Major Customers

The following table shows revenues from major customers for each of the three years ended December 31:

	2004	2003	2002
		(In millions)	
Scana Corporation[(1)]	$64	$62	$62
Alabama Gas Corporation[(2)]	45	45	44
Atlanta Gas Light Company[(1)(3)]	37	29	29

(1) A significant portion of revenues received from a subsidiary of Scana Corporation resulted from firm capacity released by Atlanta Gas Light Company under terms allowed by our tariff.

(2) In 2004 and 2003, Alabama Gas Corporation did not represent more than 10 percent of our revenues.

(3) In 2004, 2003 and 2002, Atlanta Gas Light Company did not represent more than 10 percent of our revenues.

10. Supplemental Cash Flow Information

The following table contains supplemental cash flow information for each of the three years ended December 31:

	2004	2003	2002
		(In millions)	
Interest paid, net of capitalized interest	$94	$75	$53
Income tax payments	48	25	15

11. Investments in Unconsolidated Affiliates and Transactions with Affiliates

Investments in Unconsolidated Affiliates

Our investments in unconsolidated affiliates are accounted for using the equity method of accounting and consist of our equity ownership interests in Citrus and Bear Creek.

Citrus. In March 2003, El Paso contributed its 50 percent ownership interest in Citrus to us. Citrus owns and operates Florida Gas Transmission, a 4,870 mile regulated pipeline system that extends from producing regions in Texas to markets in Florida. Since both the investment in Citrus, which is accounted for as an equity investment, and our common stock were owned by El Paso at the time of the contribution, we were required to reflect the investment in Citrus at its historical cost and include its operating results in our financial statements for all periods presented prior to its contribution.

CrossCountry owns the other 50 percent of Citrus, which was previously owned by Enron Corp. (Enron). Effective in April 2004, Enron assigned its capital stock in Citrus to CrossCountry. In September 2004, Enron sold its interest in CrossCountry to a joint venture between Southern Union and General Electric. The ownership agreements of Citrus provide each partner with a right of first refusal to purchase the ownership interest of the other partner. Our investment in Citrus is limited to our ownership of the voting stock of Citrus, and we have no financial obligations, commitments or guarantees, either written or oral, to support Citrus.

During the fourth quarter of 2004, we received $70 million of dividends from Citrus. At December 31, 2004 and 2003, our investment in Citrus was $589 million and $593 million.

Bear Creek. Through our subsidiary, Southern Gas Storage Company, we hold a 50 percent ownership interest in Bear Creek, a joint venture with TSC, our affiliate. Bear Creek owns and operates an underground natural gas storage facility located in Louisiana. The facility has a capacity of 50 Bcf of base gas and 58 Bcf of working storage. Bear Creek's working storage capacity is committed equally to the TGP system (an affiliated system), and our pipeline system under long-term contracts. Our investment in Bear Creek at December 31, 2004 and 2003, was $151 million and $138 million.

Summarized financial information of our proportionate share of our unconsolidated affiliates are presented below:

	Years Ended December 31,		
	2004	2003	2002
	(In millions)		
Operating results data:			
Operating revenues	$249	$241	$210
Operating expenses	100	112	83
Income from continuing operations	74	50	55
Net income[(1)]	74	50	55

	December 31,	
	2004	2003
	(In millions)	
Financial position data:		
Current assets	$ 121	$ 175
Non-current assets	1,603	1,821
Short-term debt	7	129
Other current liabilities	36	70
Long-term debt	506	456
Other non-current liabilities	384	555
Equity in net assets[(1)]	791	786

(1) The difference between our proportionate share of our equity investments' net income and our earnings from unconsolidated affiliates reflected in our income statement and our proportionate share of their net equity and our overall investment in the balance sheet are due primarily to timing differences between the estimated and actual equity earnings from our investments.

Transactions with Affiliates

Cash Management Program. We participate in El Paso's cash management program which matches short-term cash surpluses and needs of participating affiliates, thus minimizing total borrowings from outside sources. At December 31, 2004 and 2003, we had advanced to El Paso $171 million and $153 million. The interest rate at December 31, 2004 and 2003 was 2.0% and 2.8%. These receivables are due upon demand; however, at December 31, 2004 and 2003, we have classified these advances as non-current notes receivable from affiliates because we do not anticipate settlement within the next twelve months.

Affiliate Payables. We had accounts payable to affiliates of $8 million at December 31, 2004 and 2003. These balances arose in the normal course of business.

We also received $1 million and $10 million in deposits related to our transportation contracts with El Paso Marketing L.P. (formerly El Paso Merchant Energy L.P.), which are included in our balance sheet as current liabilities as of December 31, 2004 and 2003.

We are a party to a tax accrual policy with El Paso whereby El Paso files U.S. and certain state tax returns on our behalf. In certain states, we file and pay directly to the state taxing authorities. We have income taxes payable of $46 million at December 31, 2004 and 2003, included in taxes payable on our balance sheets. The majority of these balances will become payable to El Paso under the tax accrual policy. See Note 1 for a discussion of our tax accrual policy.

Other. In 2004, we acquired assets from our affiliates with a net book value of $4 million.

In March 2003, we declared and paid a $600 million dividend, $310 million of which was a non-cash distribution of affiliated receivables and $290 million of which was cash.

Affiliate Revenues and Expenses. El Paso allocates a portion of their general and administrative expenses to us. The allocation of expenses is based upon the estimated level of effort devoted to our operations and the relative size of our EBIT, gross property and payroll. For the years ended December 31, 2004, 2003 and 2002, the annual charges were $38 million, $42 million and $41 million. During 2004, 2003 and 2002, TGP allocated payroll and other expenses associated with shared pipeline services to us. The allocated expenses are based on the estimated level of staff and their expenses to provide these services. For the years ended December 31, 2004, 2003 and 2002, the annual charges were $11 million, $8 million and $5 million. We believe that the allocation methods are reasonable.

The following table shows revenues and charges from our affiliates for each of the three years ended December 31:

	2004	2003	2002
		(In millions)	
Revenues from affiliates	$10	$37	$45
Operation and maintenance expense from affiliates	48	48	47

12. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below:

	Quarters Ended				
	March 31	June 30	September 30	December 31	Total
			(In millions)		
2004					
Operating revenues	$128	$118	$121	$160	$527
Operating income	63	52	48	83	246
Net income	36	39	33	61	169
2003					
Operating revenues	$120	$111	$111	$140	$482
Operating income	58	50	45	76	229
Net income	44	26	28	46	144

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Southern Natural Gas Company:

In our opinion, the consolidated financial statements listed in the Index appearing under Item 15(a)(1) present fairly, in all material respects, the consolidated financial position of Southern Natural Gas Company and its subsidiaries ("the Company") at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the Index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1, the 2003 and 2002 consolidated financial statements have been restated.

/s/ PricewaterhouseCoopers LLP

Birmingham, Alabama
March 29, 2005

SCHEDULE II

SOUTHERN NATURAL GAS COMPANY
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2004, 2003 and 2002
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2004					
Allowance for doubtful accounts	$ 3	$—	$—	$—	$ 3
Valuation allowance on deferred tax assets	1	—	—	—	1
Legal reserves	1	—	—	1	2
Environmental reserves	3	1	(4)[1]	—	—
2003					
Allowance for doubtful accounts	$ 3	$—	$—	$—	$ 3
Valuation allowance on deferred tax assets	1	—	—	—	1
Legal reserves	—	—	—	1	1
Environmental reserves	4	3	(4)[1]	—	3
2002					
Allowance for doubtful accounts	$ 3	$—	$—	$—	$ 3
Valuation allowance on deferred tax assets	2	—	(1)	—	1
Environmental reserves	11	—	(7)[1]	—	4

(1) Primarily payments made for environmental remediation activities.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2004, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to our management, including the CEO and CFO, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, our CEO and CFO concluded that as a result of the material weaknesses discussed below, our disclosure controls and procedures were not effective as of December 31, 2004. Because of these material weaknesses, we performed additional procedures to ensure that our financial statements as of and for the year ended December 31, 2004, were fairly presented in all material respects in accordance with generally accepted accounting principles.

Internal Control Over Financial Reporting

During 2004, we continued our efforts to ensure our compliance with Section 404 of the Sarbanes-Oxley Act of 2002, which will apply to us at December 31, 2006. In our efforts to evaluate our internal control over financial reporting, we have identified the material weaknesses described below as of December 31, 2004. A material weakness is a control deficiency, or combination of control deficiencies, that results in a more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

Access to Financial Application Programs and Data. At December 31, 2004, we did not maintain effective controls over access to financial application programs and data. Specifically, we identified internal control deficiencies with respect to inadequate design of and compliance with our security access procedures related to identifying and monitoring conflicting roles (i.e., segregation of duties) and a lack of independent monitoring of access to various systems by our information technology staff, as well as certain users that require unrestricted security access to financial and reporting systems to perform their responsibilities. These control deficiencies did not result in an adjustment to the 2004 interim or annual consolidated financial statements. However, these control deficiencies could result in a misstatement of a number of our financial statement accounts, including property, plant and equipment, accounts payable, operating expenses and potentially others, that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

Identification, Capture and Communication of Financial Data Used in Accounting for Non-Routine Transactions or Activities. At December 31, 2004, we did not maintain effective controls related to identification, capture and communication of financial data used for accounting for non-routine transactions or activities. We identified control deficiencies related to the identification, capture and validation of pertinent information necessary to ensure the timely and accurate recording of non-routine transactions or activities, primarily related to accounting for investments in unconsolidated affiliates. These control deficiencies resulted in the restatement of our 2002 and 2003 financial statements, as reflected in this annual report on Form 10-K. These control deficiencies could result in a misstatement in the aforementioned accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

Changes in Internal Control over Financial Reporting

Changes in the Fourth Quarter 2004. There has been no change in our internal control over financial reporting during the fourth quarter of 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Changes in 2005. Since December 31, 2004, we have taken action to correct the control deficiencies that resulted in the material weaknesses described above including implementing monitoring controls in our information technology areas over users who require unrestricted access to perform their job responsibilities. Other remedial actions have also been identified and are in the process of being implemented.

ITEM 9B. OTHER INFORMATION

None.

PART III

Item 10, "Directors and Executive Officers of the Registrant;" Item 11, "Executive Compensation;" Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters;" and Item 13, "Certain Relationships and Related Transactions," have been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Audit Fees

The Audit Fees for the years ended December 31, 2004 and 2003 of $925,000 and $640,000 were for professional services rendered by PricewaterhouseCoopers LLP for the audits of the consolidated financial statements of Southern Natural Gas Company.

All Other Fees

No other audit-related, tax or other services were provided by our independent registered public accounting firm for the years ended December 31, 2004 and 2003.

Policy for Approval of Audit and Non-Audit Fees

We are a wholly owned subsidiary of El Paso and do not have a separate audit committee. El Paso's Audit Committee has adopted a pre-approval policy for audit and non-audit services. For a description of El Paso's pre-approval policies for audit and non-audit related services, see El Paso Corporation's proxy statement for its 2005 annual meeting of stockholders.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

1. Financial statements.

The following consolidated financial statements are included in Part II, Item 8 of this report:

The following financial statements of our equity investment are included on the following pages of this report:

2. Financial statement schedules.

All other schedules are omitted because they are not applicable, or the required information is disclosed in the financial statements or accompanying notes.

Citrus Corp. and Subsidiaries
Consolidated Financial Statements
Years Ended December 31, 2004, 2003 and 2002
with Report of Independent Registered Public Accounting Firm

CITRUS CORP. AND SUBSIDIARIES

TABLE OF CONTENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Citrus Corp. and Subsidiaries:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, stockholders' equity and cash flows present fairly, in all material respects, the consolidated financial position of Citrus Corp. and Subsidiaries (the "Company") at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits of these consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 23, 2005

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
(In Thousands)	2004	2003
ASSETS		
Current Assets		
Cash and cash equivalents	$ 11,645	$ 125,226
Trade and other receivables		
Customers, net of allowance of $32 and $77	41,475	39,713
Price risk management assets	—	15,024
Materials and supplies	3,113	2,915
Other	4,979	4,294
Total Current Assets	61,212	187,172
Deferred Charges and Other Assets		
Unamortized debt expense	7,936	9,051
Price risk management assets	—	58,492
Other	104,340	108,380
Total Deferred Charges and Other Assets	112,276	175,923
Property, Plant and Equipment, at cost		
Completed Plant	4,085,138	4,023,762
Construction work-in-progress	12,202	35,638
Total property, plant and equipment, at cost	4,097,340	4,059,400
Less – accumulated depreciation and amortization	1,130,593	1,072,072
Net Property, Plant and Equipment	2,966,747	2,987,328
TOTAL ASSETS	$ 3,140,235	$ 3,350,423

The accompanying notes are an integral part of these consolidated financial statements.

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(In Thousands, Except Share Data)	December 31, 2004	December 31, 2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Long-term debt due within one year	$ 13,659	$ 256,159
Accounts payable		
Trade	19,753	30,396
Affiliated companies	13,471	20,086
Accrued liabilities		
Interest	15,415	19,054
Income taxes	6,332	1,148
Other taxes	8,792	10,349
Price risk management liabilities	—	25,136
Exchange gas imbalances, net	5,266	12,320
Other	1,518	283
Total Current Liabilities	84,206	374,931
Long-Term Debt	1,012,314	908,972
Deferred Credits		
Deferred income taxes	746,035	676,341
Price risk management liabilities	—	80,446
Other	13,274	13,618
Total Deferred Credits	759,309	770,405
Stockholders' Equity		
Common stock, $1 par value; 1,000 shares authorized, issued and outstanding	1	1
Additional paid-in capital	634,271	634,271
Accumulated other comprehensive income	(15,800)	(17,247)
Retained earnings	665,934	679,090
Total Stockholders' Equity	1,284,406	1,296,115
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 3,140,235	$ 3,350,423

The accompanying notes are an integral part of these consolidated financial statements.

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
(In Thousands)	2004	2003	2002
Revenues			
Gas sales	$ 44,996	$ 104,370	$ 102,166
Gas transportation, net	467,422	442,010	419,636
	512,418	546,380	521,802
Costs and Expenses			
Natural gas purchased	48,921	99,130	91,925
Operations and maintenance	81,306	117,086	89,993
Depreciation and amortization	68,053	64,522	58,101
Taxes – other than income taxes	29,565	27,436	21,859
	227,845	308,174	261,878
Operating Income	284,573	238,206	259,924
Other Income (Expense)			
Interest expense, net	(94,048)	(104,653)	(92,668)
Allowance for funds used during construction	1,136	5,804	17,141
Other, net	14,403	(14,587)	(28,082)
	(78,509)	(113,436)	(103,609)
Income Before Income Taxes	206,064	124,770	156,315
Income Tax Expense	79,220	48,554	59,728
Net Income	$ 126,844	$ 76,216	$ 96,587

The accompanying notes are an integral part of these consolidated financial statements.

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In Thousands)	Year Ended December 31, 2004	2003	2002
Common Stock			
Balance, beginning and end of year	$ 1	$ 1	$ 1
Additional Paid-in Capital			
Balance, beginning and end of year	634,271	634,271	634,271
Accumulated Other Comprehensive Income (Loss):			
Balance, beginning of year	(17,247)	(18,453)	(6,713)
Deferred loss on cash flow hedge	—	—	(12,280)
Recognition in earnings of previously deferred (gains) and losses related to derivative instruments used as cash flow hedges	1,447	1,206	540
Balance, end of year	(15,800)	(17,247)	(18,453)
Retained Earnings			
Balance, beginning of year	679,090	602,874	506,287
Net income	126,844	76,216	96,587
Dividends	(140,000)	—	—
Balance, end of year	665,934	679,090	602,874
Total Stockholders' Equity	$ 1,284,406	$ 1,296,115	$ 1,218,693

The accompanying notes are an integral part of these consolidated financial statements.

CITRUS CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Twelve Months Ended December 31,		
(In Thousands)	2004	2003	2002
Cash Flows From Operating Activities			
Net income	$ 126,844	$ 76,216	$ 96,587
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	68,053	64,522	58,101
Amortization of hedge loss in other comprehensive income	1,447	1,206	540
Amortization of premium and swap hedge loss in long term debt	341	392	176
Amortization of regulatory assets and other deferred charges	5,205	12,000	2,609
Amortization of debt costs	1,116	1,840	1,661
Deferred income taxes	69,694	24,271	56,154
Non-cash interest income	—	—	(2,025)
Fair value loss of reverse swap	—	—	2,575
Price risk management fair market valuation revaluation	10,980	20,599	22,897
Price risk management gain on buy out of gas sales contract	(19,884)	—	—
Allowance for funds used during construction	(1,136)	(5,804)	(17,141)
Changes in assets and liabilities			
Changes in working capital			
Trade and other receivables	(1,762)	9,443	21,634
Materials and supplies	(198)	422	350
Trade and other payables	(17,258)	(7,029)	(2,219)
Accrued liabilities	(10)	3,746	(5,711)
Other current assets and liabilities	(7,928)	9,863	304
Price risk management assets and liabilities	(23,162)	7,150	(22,781)
Other, net	2,169	14,561	(20,885)
Net Cash Provided by Operating Activities	214,511	233,398	192,826
Cash Flows From Investing Activities			
Additions to property, plant and equipment	(47,694)	(142,334)	(242,804)
Allowance for funds used during construction	1,136	5,804	17,141
Retirements and disposition of property, plant and equipment, net	(1,288)	(1,074)	2,444
Net Cash Used in Investing Activities	(47,846)	(137,604)	(223,219)
Cash Flows From Financing Activities			
Dividends	(140,000)	—	—
Proceeds from issuance of long-term debt	117,000	—	250,000
Long-term debt finance costs	(746)	—	(2,743)
Repayment of long-term debt	—	(59,500)	(74,700)
Principal payments on long-term debt	(256,500)	(25,750)	(25,750)
Anticipatory hedge settlement (other comprehensive income)	—	—	(12,280)
Interest rate swap settlement	—	—	(550)
Net Cash Provided by/(Used in) Financing Activities	(280,246)	(85,250)	133,977
Increase (Decrease) in Cash and Cash Equivalents	(113,581)	10,544	103,584
Cash and Cash Equivalents, Beginning of Year	125,226	114,682	11,098
Cash and Cash Equivalents, End of Year	$ 11,645	$ 125,226	$ 114,682

Additional cash flow information:			
The Company made the following interest and income tax payments:			
Interest paid (net of amounts capitalized)	$ 95,770	$ 105,641	$ 90,284
Income taxes paid	4,432	19,488	12,462

The accompanying notes are an integral part of these consolidated financial statements.

CITRUS CORP. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Reporting Entity

Citrus Corp. (Citrus), a holding company formed in 1986, owns 100 percent of the stock of Florida Gas Transmission Company (Transmission), Citrus Trading Corp. (Trading) and Citrus Energy Services, Inc. (CESI), collectively the Company. At December 31, 2004, the stock of Citrus was owned 50 percent by El Paso Citrus Holdings, Inc. (EPCH), a wholly owned subsidiary of Southern Natural Gas Company (Southern), as transferred by Southern in January 2004, and 50 percent by CrossCountry Citrus, LLC (CCC), a wholly owned subsidiary of CrossCountry Energy, LLC (CrossCountry). Southern's 50 percent ownership had previously been contributed by its parent, El Paso Corporation (El Paso) in March 2003. CrossCountry was a wholly owned subsidiary of Enron Corp. (Enron) and certain of its subsidiary companies. Effective November 17, 2004, CrossCountry became a wholly owned subsidiary of CCE Holdings, LLC (CCE Holdings), which is a joint venture owned by subsidiaries of Southern Union Company (Southern Union) (50 percent), GE Commercial Finance Energy Financial Services (GE) (30 percent) and four minority interest owners (20 percent in the aggregate). All of the voting interests in CCE Holdings are owned by Southern Union and GE.

Transmission, an interstate gas pipeline extending from South Texas to South Florida, is engaged in the interstate transmission of natural gas and is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Trading ceased all trading activities effective the fourth quarter of 1997, but continued to fulfill its obligations under the remaining gas purchase and gas sale contracts through the last quarter of 2004. During 2004, it sold its remaining contracts and no longer has any gas purchase or gas sale contracts.

CESI primarily provides transportation management and financial services to customers of Transmission. CESI terminated its Operations and Maintenance (O&M) business due to increased insurance costs and pipeline integrity legislation that affects operators.

(2) Significant Accounting Policies

Regulatory Accounting – Transmission is subject to regulation by the FERC. Transmission's accounting policies generally conform to Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, certain assets and liabilities that result from the regulated ratemaking process are recorded that would not be recorded under accounting principles generally accepted in the United States for non-regulated entities.

Principles of Consolidation – The consolidated financial statements include the accounts of Citrus and its wholly owned subsidiaries. All significant intercompany transactions and accounts have been eliminated in consolidation.

Cash and Cash Equivalents – Cash equivalents consist of highly liquid investments with original maturities of three months or less. The carrying amount of cash and cash equivalents approximates fair value because of the short maturity of these investments.

Reclassifications – Certain reclassifications have been made to the consolidated financial statements for prior years to conform with the current year presentations with no impact on reported net income or stockholders' equity.

Materials and Supplies – Materials and supplies are valued at the lower of cost or market value. Materials transferred out of warehouses are priced out at average cost.

(2) Significant Accounting Policies (continued)

Revenue Recognition – Revenues consist primarily of gas transportation services. Reservation revenues on firm contracted capacity are recognized ratably over the contract period. For interruptible or volumetric based services, revenues are recorded upon the delivery of natural gas to the agreed upon delivery point. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. Transmission is subject to FERC regulations and, as a result, revenues collected may be required to be refunded in a final order of a future rate proceeding or as a result of a rate settlement.

Accounting for Derivative Instruments – The Company engaged in price risk management activities for both trading and non-trading activities and accounted for those contracts under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (see Note 4). Instruments utilized in connection with trading activities were accounted for on a mark-to-market basis and were reflected at fair value as Assets and Liabilities from Price Risk Management Activities in the Consolidated Balance Sheets. The Company classified price risk management activities as either current or non-current assets or liabilities based on their anticipated settlement date. Earnings from revaluation of price risk management assets and liabilities were included in Other Income (Expense). Cash flow hedge accounting is utilized for non-trading purposes to hedge the impact of interest rate fluctuations associated with the Company's debt. Unrealized gains and losses from cash flow hedges, to the extent such amounts are effective, are recognized as a component of other comprehensive income, and subsequently recognized in earnings in the same periods as the hedged forecasted transaction affects earnings. The ineffective component from cash flow hedges is recognized in Other Income (Expense) each period. In instances where the hedge no longer qualifies as being effective, hedge accounting is terminated prospectively and the accumulated gain or loss is recognized in earnings in the same periods during which the hedged forecasted transaction affects earnings. Where fair value hedge accounting is appropriate, the offset that is attributed to the risk being hedged is recorded as an adjustment to the hedged item in the statement of operations (see Note 4). In the Company's cash flow statement, cash inflows and outflows associated with the settlement of the price risk management activities are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported as trade receivables or payables on the balance sheet.

Property, Plant and Equipment – Property, Plant and Equipment (see Note 10) consists primarily of natural gas pipeline and related facilities. The Company amortizes that portion of its investment in Transmission and other subsidiaries which is in excess of historical cost (acquisition adjustment) on a straight-line basis at an annual composite rate of 1.6 percent based upon the estimated remaining useful life of the pipeline system. Transmission has provided for depreciation of assets net of estimated salvage value, on a straight-line basis, at an annual composite rate of 1.74 percent, 1.66 percent, and 1.52 percent for 2004, 2003, and 2002, respectively. The overall remaining useful life for Transmission's assets at December 31, 2004, is 40 years.

Property, Plant and Equipment is recorded at its original cost. Transmission capitalizes direct costs, such as labor and materials, and indirect costs, such as overhead, interest and an equity return component (see following paragraph). Costs of replacements and renewals of units of property are capitalized. The original costs of units of property retired are charged to the accumulated depreciation, net of salvage and removal costs. Transmission charges to maintenance expense the costs of repairs and renewal of items determined to be less than units of property.

The allowance for funds used during construction consists, in general, of the net cost of borrowed funds used for construction purposes and a reasonable rate on other funds when so used (the AFUDC rate). The allowance is determined by applying the AFUDC rate to the amount of

(2) Significant Accounting Policies (continued)

construction work-in-progress. Capitalization begins at the time the Company begins the continuous accumulation of costs in a construction work order on a planned progressive basis and ends when the facilities are placed in service.

The Company applies the provisions of SFAS No. 143, *Accounting for Asset Retirement Obligation* to record a liability for the estimated removal costs of assets where there is a legal obligation associated with removal. Under this standard, the liability is recorded at its fair value, with a corresponding asset that is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The Company adopted SFAS No. 143, beginning January 1, 2003. A comprehensive study was made at that time and it was determined that the adoption of this standard did not have a financial statement impact. The Company will continue to monitor these requirements.

The Company applies the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* to account for asset impairments. Under this standard, an asset is evaluated for impairment when events or circumstances indicate that a long-lived asset's carrying value may not be recovered. These events include market declines, changes in the manner in which an asset was intended to be used, decisions to sell an asset, and adverse changes in the legal or business environment such as adverse actions by regulators.

Compressor Overhaul Expenditures – In 2003, Transmission changed its method of accounting for compressor overhaul costs by adopting a method for current expense recognition of compressor overhaul costs. This change was the result of Management's determination that such costs previously deferred would not be recovered through future tariff rates. In prior years, such costs were deferred and amortized ratably over the expected service life of the applicable overhaul item. An unamortized balance of $7.0 million applicable to the previous method was expensed in 2003. An additional amount of $6.5 million related to 2003 overhaul costs, which would have been deferred under the previous methodology, was also expensed. In 2004, the remaining unamortized overhaul costs of $0.5 million were expensed and an additional $4.8 million of overhaul costs related to 2004 overhauls were also expensed under the new methodology.

Income Taxes – The Company accounts for income taxes (see Note 5) under the provisions of SFAS No. 109, *Accounting for Income Taxes.* SFAS No. 109 provides for an asset and liability approach to accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases.

Trade Receivables – The Company establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables. The Company considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectibility. Unrecovered trade accounts receivable charged against the allowance for doubtful accounts were $0.0 and $0.3 million in 2004 and 2003, respectively.

Use of Estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(3) Long-Term Debt and Other Financing Arrangements

Long-term debt outstanding at December 31, 2004, and 2003, was as follows (in thousands):

	2004	2003
Citrus		
8.490% Notes due 2007-2009	$ 90,000	$ 90,000
	90,000	90,000
Transmission		
9.750% Notes due 1999-2008	26,000	32,500
8.630% Notes due 2004	—	250,000
10.110% Notes due 2009-2013	70,000	70,000
9.190% Notes due 2005-2024	150,000	150,000
7.625% Notes due 2010	325,000	325,000
7.000% Notes due 2012	250,000	250,000
Revolving Credit Agreement due 2007	117,000	—
Unamortized Debt Premium and Swap Loss	(2,027)	(2,369)
	935,973	1,075,131
Total Outstanding	1,025,973	1,165,131
Long-Term Debt Due Within One Year	(14,000)	(256,500)
Unamortized Debt Premium and Swap Loss Within One Year	341	341
	$ 1,012,314	$ 908,972

Annual maturities and sinking fund requirements on long-term debt outstanding as of December 31, 2004, were as follows (in thousands):

Year	Principal Amount	Amortization *(1)*	Total
2005	$ 14,000	$ (341)	$ 13,659
2006	14,000	(341)	13,659
2007	161,000	(341)	160,659
2008	44,000	(341)	43,659
2009	51,500	(341)	51,159
Thereafter	743,500	(322)	743,178
	$ 1,028,000	$ (2,027)	$ 1,025,973

(1) Amortization of the debt premium and swap loss recognized on financing arrangements.

On April 1, 2004, Transmission paid $6.5 million due annually under its 9.75 percent Notes. Transmission's 8.63 percent Notes were repaid on November 1, 2004, in the amount of $250.0 million principal in addition to its accrued interest. This note was classified as a current obligation in the accompanying balance sheet at December 31, 2003. The principal payments from the two transactions were funded utilizing current working capital, current operating cash flows and partially by borrowings under Transmission's 2004 Revolver mentioned below. At December 31, 2004, the portion of current obligations due which are not repaid through current working capital and future operating cash flows will be financed utilizing its existing 2004 Revolver (see below).

(3) Long-Term Debt and Other Financing Arrangements (continued)

Transmission had a Revolving Credit Agreement ("2001 Revolver"), whose last commitment amount totaled $70.0 million and was due November 2004. There was no outstanding balance under the 2001 Revolver at December 31, 2003. Transmission had an aggregate of $0.6 million in letters of credit under the 2001 Revolver outstanding at December 31, 2003. During May 2004, approximately $0.5 million of Transmission's letters of credit remained and at that time they were released and $0.3 million were converted into surety bonds.

On August 13, 2004, Transmission terminated the 2001 Revolver and replaced it with another Revolving Credit Agreement ("2004 Revolver") with an initial commitment level of $50.0 million. The 2004 Revolver will terminate in October 2007. On October 29, 2004, Transmission borrowed $10.0 million that was utilized to assist the funding of the scheduled Transmission 8.63 percent Notes debt repayment on November 1, 2004. Effective November 15, 2004, the commitment level was increased by $125.0 million to $175.0 million. On November 17, 2004, Transmission borrowed an additional $135.0 million to assist in the funding of a $135.0 million dividend from Transmission to Citrus. Citrus paid a $140.0 million cash dividend to its equity owners on November 17, 2004. Since that time, Transmission has routinely utilized the 2004 Revolver to fund working capital needs. On December 31, 2004, the amount drawn under the 2004 Revolver was $117.0 million with a weighted average interest rate of 3.24 percent (based on LIBOR plus 0.95 percent). Remaining unamortized debt issuance costs of $0.3 million on the 2001 Revolver were expensed when it was terminated in 2004, and the debt issuance costs accumulated for the 2004 Revolver were $0.7 million.

Transmission may incur additional debt to refinance maturing obligations if the refinancing does not increase aggregate indebtedness, and thereafter, if Transmission and the Company's consolidated debt does not exceed specific debt to total capitalization ratios, as defined. Incurrence of additional indebtedness to refinance the current maturities would not result in a debt to capitalization ratio exceeding these limits.

Citrus has note agreements that contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets, and the payment of dividends, and require maintaining certain restrictive financial covenants, including required ratios of consolidated funded debt to consolidated capitalization, consolidated funded debt to consolidated net tangible assets, and consolidated cash flow to consolidated fixed charges. The agreements relating to Transmission's promissory notes include, among other things, restrictions as to the payment of dividends and maintaining certain restrictive financial covenants, including a required ratio of consolidated funded debt to total capitalization. As of December 31, 2004, the Company was in compliance with both affirmative and restrictive covenants of the note agreements.

All of the debt obligations of Citrus and Transmission have events of default that contain commonly used cross-default provisions. An event of default by either Citrus or Transmission on any of their borrowed money obligations, in excess of certain thresholds which is not cured within defined grace periods, would cause the other debt obligations of Transmission and Citrus to be accelerated. During 2003 and 2004, Transmission as borrower, sought and obtained waivers on the 2001 Revolver; however; during 2003 and 2004, Transmission had no outstanding borrowings under this facility which could cause an event of cross-default.

In October 2003, Citrus paid the remaining principal of $78.8 million on the 11.10 percent Note due in 2006 and incurred a $0.7 million pre-payment expense.

(4) Derivative Instruments

The Company determined that its gas purchase contracts for resale and related gas sales contracts were derivative instruments and recorded these at fair value as price risk management assets and liabilities under SFAS No. 133, as amended. The valuation was calculated using a discount rate adjusted for the Company's borrowing premium of 250 basis points, which created an implied reserve for credit and other related risks. The Company estimated the fair value of all derivative instruments based on quoted market prices, current market conditions, estimates obtained from third-party brokers or dealers, or amounts derived using internal valuation models. During the fourth quarter of 2004, the Company sold its remaining derivative contract without a material impact on the consolidated statements of income. At December 31, 2004, the fair value for the price risk management assets and liabilities was $0.0 and $0.0 million, respectively. At December 31, 2003, the fair value for the price risk management assets and liabilities was $73.5 and $105.6 million, respectively. The Company performed a quarterly revaluation on the carrying balances that were reflected in current earnings. The impact to earnings from revaluation, mostly due to price fluctuations, was a loss of $11.0, $20.6, and $22.9 million for 2004, 2003, and 2002, respectively.

Prior to the Enron bankruptcy, Enron North America Corp. (ENA) was the principal counterparty to Trading's gas purchase and sale agreements (including swaps). ENA has rejected these contracts in bankruptcy. A pre-petition gas purchase payable to ENA of $12.4 million was reversed in 2003 when it was determined that the Company had a right of offset against claims for pre-petition receivables. Pursuant to an existing operating agreement which was rejected by ENA in 2003 but under which an El Paso affiliate performed, an affiliate of El Paso was required to buy gas, purchased from a significant third party, that exceeded the requirements of Trading's existing sales contracts. Under this third party contract, gas was purchased primarily at rates based upon an indexed oil price formula. This gas was then sold primarily at market rates for gas. On April 16, 2003, the significant third party supplier terminated the supply contract. Trading then only purchased the requirements to fulfill existing sales contracts from third parties at market rates. As a result of these developments, the cash flow stream was dependent on variable pricing, whereas before Enron's bankruptcy, the cash flow stream was fixed (under certain swaps). In June 2004, the Company paid $16.2 million and recorded an accrual for a contingent payment of up to $6.5 million to terminate a gas sales contract with a third-party, resulting in a net gain totaling $19.9 million. The contingent payment will be paid to the third-party from any future proceeds resulting from the settlement of either the ENA bankruptcy claims or the Duke Energy LNG Sales, Inc. (Duke) litigation (see below). In October 2004, the Company sold its remaining derivative contracts without a material impact on the Consolidated Statement of Income, as the sales price approximated the contracts fair value.

Due to a dispute (see Note 13) during 2003, Duke purported to terminate and discontinued performance under a natural gas purchase and supply contract between it and Trading, which Trading subsequently terminated. As a result of this contract termination, during 2003, Trading discontinued the application of fair market value accounting for this contract, and wrote off the value of the related price risk management assets as a charge to Other Income (Expense) in the accompanying statement of income. Pursuant to the terms of the contract and also during 2003, Trading issued to Duke, the counterparty, a termination invoice for approximately $187.0 million. As a result of the ongoing litigation regarding this matter, the termination invoice amount was recognized, net of reserves (which includes certain other matters), as an offsetting gain to Other Income (Expense) and is recorded as a long term receivable (see Note 11) of $66.9 and $72.5 million at December 31, 2004 and 2003, respectively.

During 2001, Transmission entered into an interest rate swap transaction to hedge the fair value risk associated with $135 million of its existing long-term fixed rate debt. This transaction qualified

(4) Derivative Instruments (continued)

and was accounted for as a fair value hedge in accordance with SFAS No. 133. This instrument was terminated in May 2002 with a fair value loss of $2.6 million being recorded in long term debt, which is being amortized over the life of the debt issued as an adjustment to interest expense.

During 2002, Transmission initiated a new swap to hedge interest rate changes, which could occur between the initiation date of the swap and the issuance date of the July 2002 $250 million note offering. The aggregate notional amount of this swap was $250 million. This swap was terminated effective July 18, 2002. The $12.3 million fair value loss at the termination of the swap agreement was recognized as other comprehensive loss and is being amortized over the life of the related debt issue as an adjustment to interest expense.

(5) Income Taxes

The principal components of the Company's net deferred income tax liabilities at December 31, 2004, and 2003 are as follows (in thousands):

	2004	2003
Deferred income tax assets		
Alternative minimum tax credit	$ 9,577	$ 9,003
Regulatory and other reserves	6,295	4,593
Price risk management activities	—	11,963
Other	120	137
	15,992	25,696
Deferred income tax liabilities		
Depreciation and amortization	717,223	658,501
Deferred charges and other assets	27,295	28,528
Regulatory costs	13,264	11,052
Other	4,245	3,956
	762,027	702,037
Net deferred income tax liabilities	$ 746,035	$ 676,341

Total income tax expense for the years ended December 31, 2004, 2003 and 2002 is summarized as follows (in thousands):

	2004	2003	2002
Current Tax Provision (Benefit)			
Federal	$ 7,561	$ 19,215	$ 4,996
State	1,965	5,068	(1,422)
	9,526	24,283	3,574
Deferred Tax Provision (Benefit)			
Federal	60,808	21,930	47,101
State	8,886	2,341	9,053
	69,694	24,271	56,154
Total income tax expense	$ 79,220	$ 48,554	$ 59,728

(5) Income Taxes (continued)

The differences between taxes computed at the U.S. federal statutory rate of 35 percent and the Company's effective tax rate for the years ended December 31, 2004, 2003, and 2002 are as follows (in thousands):

	2004	2003	2002
Statutory federal income tax provision	$ 72,122	$ 43,670	$ 54,709
State income taxes, net of federal benefit	7,053	4,816	4,960
Other	45	68	59
Income tax expense	$ 79,220	$ 48,554	$ 59,728
Effective Tax Rate	38.4%	38.9%	38.2%

The Company has an alternative minimum tax (AMT) credit which can be used to offset regular income taxes payable in future years. The AMT credit has an indefinite carry-forward period. For financial statement purposes, the Company has recognized the benefit of the AMT credit carry-forward as a reduction of deferred tax liabilities.

The Company files a consolidated federal income tax return separate from its parents.

(6) Employee Benefit Plans

During 2003, the employees of the Company were covered under Enron's employee benefit plans. The Company's participation in the Enron benefit plans terminated during November 2004.

Enron maintained a pension plan that was a noncontributory defined benefit plan, the Enron Corp. Cash Balance Plan (the Cash Balance Plan), covering certain Enron employees in the United States and certain employees in foreign countries. The basic benefit accrual was 5 percent of eligible annual base pay. Pension expense charged to the Company by Enron was $0.3, $1.9, and $1.7 million for 2004, 2003, and 2002, respectively. This excludes the Cash Balance termination amount discussed below.

In June 2004, the Pension Benefit Guaranty Corporation (PBGC) filed a complaint in the United States District Court for the Southern District of Texas to terminate the Cash Balance Plan and other pension plans of Enron debtor companies and affiliates (the Plans). Because the Company is not a part of an Enron "controlled group of corporations" within the meaning of Section 414 of the Tax Code, if the Plans were to be terminated pursuant to the PBGC action or in other than standard terminations, the Company would be liable for only its proportionate share of any underfunding that may exist in the Cash Balance Plan at the time of such termination, though there can be no assurance that the PBGC might not take a different position. In addition, the Company, as a former participating employer in certain Enron benefit plans, may have indemnity obligations in favor of committee members and others under certain Enron benefit plans that are the subject of litigation asserting, among other claims, breaches of fiduciary duty. Under certain circumstances, the PBGC may enforce ERISA Title IV liability through the imposition of liens. On September 10, 2004, Enron agreed to put $321.8 million in an escrow account to cover, among other things, the unfunded benefit liabilities related to the Plans. The escrow account was funded with a portion of the proceeds from Enron's sale of CrossCountry.

In 2003, the Company recognized its portion of the expected Cash Balance Plan settlement by recording a $9.6 million current liability and a charge to operating expense. In 2004, with the settlement of the rate case (see Note 9), Transmission has recognized a regulatory asset for its portion, $9.3 million, with a reduction to operating expense. Per the rate case settlement,

(6) Employee Benefit Plans (continued)

Transmission will amortize, over five years retroactive to April 1, 2004, its allocated share of costs to fully fund and terminate the Cash Balance Plan. Amortization recorded in 2004 was $1.4 million. At December 31, 2004, Transmission has a remaining regulatory asset balance for this matter of $7.9 million. Based on the current status of the Cash Balance Plan termination cost and the amount expected to be allocated to the Company as its proportionate share of the plan's termination liability, the Company continues to believe its accruals related to this matter are adequate. Although there can be no assurance that amounts ultimately allocated to and paid by the Company will not be materially different, we do not believe that the ultimate resolution of these matters will have a materially adverse effect on the Company's consolidated financial position or cash flows, but it could have significant impact on the results of operations in future periods.

Effective November 1, 2004, the employees of the Company were transferred to an affiliated entity, CrossCountry Energy Services, LLC (CCES) and during November 2004, employee insurance coverages migrated (without lapse) from Enron plans to new CCES welfare and benefit plans. Effective March 1, 2005, essentially all such employees were transferred to Transmission and became eligible at that time to participate in employee welfare and benefit plans adopted by Transmission.

Effective March 1, 2005, Transmission adopted the Florida Gas Transmission Company 401(k) Savings Plans (the Plans). All employees of Transmission are eligible to participate and, under one Plan, may contribute up to 50 percent of pre-tax compensation, subject to IRS limitations. This Plan allows additional "catch-up" contributions by participants over age 50, and allows Transmission to make discretionary profit sharing contributions for the benefit of all participants. Transmission matches 50 percent of participant contributions under this Plan up to a maximum of 4 percent of eligible compensation. Participants vest in such matching and any profit sharing contributions at the rate of 20 percent per year, except that participants with five years of service at the date of adoption of the Plan were immediately vested. Administrative costs of the Plan and certain asset management fees are paid from Plan assets.

Enron provided certain post-retirement medical, life insurance and dental benefits to eligible employees and their eligible dependents through November 30, 2004. The net periodic post-retirement benefit costs charged to the Company by Enron were $0.6, $1.2, and $1.3 million for 2004, 2003, and 2002 respectively. Substantially all of these amounts relate to Transmission and are being recovered through rates. During the period December 1, 2004 through February 28, 2005, coverage to eligible employees and their eligible dependents was provided by CrossCountry Energy Retiree Health Plan, which provides only medical benefits. Effective March 1, 2005, such benefits are provided under a plan sponsored by Transmission.

Transmission was a participating employer in the Enron Gas Pipelines Employee Benefit Trust (the Trust), a voluntary employees' beneficiary association under Section 501(c)(9) of the Tax Code, which provides benefits to former employees of Transmission and certain other Enron affiliates pursuant to the Enron Corp. Medical Plan and the Enron Corp. Medical Plan for Inactive Participants. Enron has made the determination that it will partition the Trust and distribute the assets and liabilities of the Trust among the participating employers of the Trust on a pro rata basis according to the contributions and liabilities associated with each participating employer. The Trust Committee will have final approval on allocation methodology for the Trust assets. Enron filed a motion, which has been stayed, which provides that each participating employer expressly assumes liability for its allocable portion of retiree benefits and releases Enron from any liability with respect to the Trust in order to receive the assets of the Trust. The Company cannot determine the impact on financial statements at this time.

(6) Employee Benefit Plans (continued)

Certain retirees of Transmission were covered under a deferred compensation plan managed and funded by Enron subsidiaries, one previously sold and the other now in bankruptcy. This matter has been included as part of the claim filed by Transmission against Enron and another affiliated bankrupt company. Transmission and Enron agreed in principle to a settlement, resulting in an allowed claim by Transmission of approximately $3.4 million against Enron for the deferred compensation plan. Documents were executed in February 2005 and await only the approval of the bankruptcy court. As a result of this settlement, a deferred compensation plan liability of $1.8 million was recognized by Transmission in 2004 (see Note 12). Anticipated proceeds due from Enron for this bankruptcy claim are $0.5 million and recorded as a long term receivable at December 31, 2004 (see Note 11).

(7) Major Customers

Revenues from individual third party and affiliate customers exceeding 10 percent of total revenues for the years ended December 31, 2004, 2003, and 2002 were approximately as listed below (in millions).

Customers	2004	2003	2002
Florida Power & Light Company	$ 189.5	$ 186.6	$ 171.2
El Paso Merchant Energy (affiliate)	3.8	14.5	60.9

At December 31, 2004, and 2003, the Company had receivables of approximately $15.0 and $15.1 million from Florida Power & Light Company. At December 31, 2004, and 2003, the Company had a pooling deposit of $0.1 and $0.1 million and a prepayment of approximately $0.0 and $0.4 million, respectively from El Paso Merchant Energy.

(8) Related Party Transactions

In December 2001, Enron and certain of its subsidiaries filed voluntary petitions for Chapter 11 reorganization with the U.S. Bankruptcy court. At December 31, 2004, Transmission and Trading had aggregate outstanding claims with the Bankruptcy Court against Enron and affiliated bankrupt companies of $220.6 million. Of these claims, Transmission and Trading filed claims totaling $68.1 and $152.5 million, respectively. Transmission and Trading claims pertaining to contracts rejected by ENA were $21.4 and $152.3 million, respectively (see Note 13). Transmission's claims against ENA on transportation contracts were reduced by approximately $21.2 million when a third party took assignment of ENA's transportation contracts. In 2004, Transmission settled the amount of all of its claims (including the deferred compensation retiree claim) against Enron and a subsidiary debtor. Total allowed claims (including debtor set-offs) are $13.3 million. The settlement documents have been finalized, but not executed (except for the deferred compensation claim discussed in Note 6) and also await bankruptcy court approval. In March 2005, ENA filed objections to Trading's claim.

Transmission has a construction reimbursement agreement with ENA under which amounts owed to Transmission are delinquent. These obligations total approximately $7.4 million and are included in Transmission's filed bankruptcy claims. These receivables were fully reserved by Transmission prior to 2003. Transmission has also filed proofs of claims regarding other claims against ENA in the bankruptcy proceeding (see Note 13). In its rate case filed with the FERC (see Note 9), Transmission has proposed to recover the estimated under-recovery on this obligation by rolling in the costs of the facilities constructed, less the estimated recovery from ENA, into its rates.

(8) Related Party Transactions (continued)

Under the Settlement filed by Transmission on August 13, 2004, and approved by the FERC on December 21, 2004, Transmission will recover the difference (see Notes 9 and 13) in its tariff rates.

The Company incurs certain corporate administrative expenses from Enron and its affiliates (including CCES, which was sold on November 17, 2004, as part of CrossCountry to Southern Union and GE (see Note 1)). These services include administrative, legal, compliance, and pipeline operations emergency services. The agreement expired on June 30, 2001, and was not extended; however, Enron subsidiaries continued to provide services under the terms of the original operating agreement. The Company expensed approximately $11.5, $13.0, and $14.9 million, for these charges for the years ended 2004, 2003, and 2002, respectively.

Services provided by bankrupt Enron affiliates were allocated to the Company pursuant to a Bankruptcy Court ordered allocation methodology. Under that methodology, the Company was obligated to pay allocated amounts, subject to certain terms and conditions. Consistent with these terms and conditions, the Company accrued and paid the full amount for services it received directly from the bankrupt Enron affiliates. Indirect Enron service allocations under this methodology were capped commensurate with 2001 levels. Effective April 1, 2004, services previously provided by bankrupt Enron affiliates to the Company pursuant to the allocation methodology ordered by the Bankruptcy Court were covered and charged under the terms of the Transition Services Agreement/Transition Services Supplemental Agreement (TSA/TSSA). This agreement between Enron and CrossCountry is administered by CCES who has allocated to the Company its share of total costs. Effective November 17, 2004, an Amended TSA/TSSA agreement was put into effect. The total costs are not materially different than those previously charged. The Company expensed $1.7, $2.1, and $2.1 million for indirect services and $8.2, $9.4 and $10.7 million for direct services, for the years ended December 31, 2004, 2003, and 2002, respectively.

The Company provided natural gas sales and transportation services to Enron and El Paso affiliates at rates equal to rates charged to non-affiliated customers in the same class of service. Revenues related to these transportation services were approximately $0.0, $0.0, and $0.4 million from Enron affiliates and $3.7, $5.3, and $5.7 million from El Paso affiliates for the years ended December 31, 2004, 2003, and 2002, respectively. The Company's gas sales were approximately $0.0, $0.0, and $0.0 million to Enron affiliates and $0.1, $9.2, and $55.2 million to El Paso affiliates for the years ended December 31, 2004, 2003, and 2002, respectively. The Company also purchased gas from affiliates of Enron of approximately $5.8, $3.7, and $0.0 million and from affiliates of El Paso of approximately $19.5, $26.9, and $19.9 million for the years ended December 31, 2004, 2003, and 2002, respectively. Transmission also purchased transportation services from Southern in connection with its Phase III Expansion completed in early 1995. Transmission contracted for firm capacity of 100,000 Mcf/day on Southern's system for a primary term of 10 years, to be continued for successive terms of one year each thereafter unless cancelled by either party, by giving 180 days notice to the other party prior to the end of the primary term or any yearly extension thereof. The amount expensed for these services totaled $6.5, $6.6, and $6.9 million for the years ended December 31, 2004, 2003, and 2002, respectively.

The Company either jointly owns or licenses with other Enron and CrossCountry affiliates certain computer and telecommunications equipment and software that is critical to the conduct of its business. In other cases, such equipment or software is wholly-owned by such affiliates, and the Company has no ownership interest in such equipment or software but is permitted to use or access such equipment or software. Transmission participated in business applications that are shared among the Enron pipelines. All participating pipelines use the same common base system and also have a custom pipeline-specific component. Each pipeline pays for its custom development

(8) Related Party Transactions (continued)

component and shares in the common base system development costs. There are specific software licenses that were entered into by an Enron affiliate that entitle Transmission to usage of the software licenses. Fees for this arrangement are included in the amounts paid under the Amended TSA/TSSA agreement.

Transmission is a party to a Participation Agreement, dated effective as of November 1, 2002, with Enron and Enron Net Works to provide Electronic Data Interchange (EDI) services through an outsourcing arrangement with EC Outlook. Enron renegotiated an existing agreement with EC Outlook; the amended agreement lowered the cost of EDI services and also provided the means for Transmission to be compliant with the most recent North American Energy Standards Board (NAESB) EDI standards. The contract has a termination date of November 30, 2005. Fees for this arrangement are included in the amounts paid under the Amended TSA/TSSA agreement.

Transmission entered into a 20-year compression service agreement with Enron Compression Services Company (ECS) in March 2000, as amended, service under which commenced on April 1, 2002. This agreement requires Transmission to pay ECS to provide electric horsepower capacity and related horsepower hours to be used to operate Compressor Station No. 13A, which consists of an electric compressor unit. Amounts paid to ECS in 2004, 2003 and 2002, totaled \$2.4, \$2.3 and \$1.5 million respectively. Under related agreements, ECS is required to pay Transmission an annual lease fee and a monthly operating and maintenance fee to operate and maintain the facilities. Amounts received from ECS in 2004, 2003, and 2002 for these services were \$0.4, \$0.4 and \$0.3 million, respectively. A Netting Agreement, dated effective November 1, 2002, was executed with ECS, providing for the netting of payments due under each of the O&M, lease, and compression service agreements with ECS. Effective December 1, 2004, ECS assigned all of its interest in the compression services and related agreements to Paragon ECS Holdings, LLC, a non-affiliated entity.

(9) Regulatory Matters

Transmission's previously effective rates were established pursuant to a Stipulation and Agreement (Rate Case Settlement) which resolved all issues in Transmission's Natural Gas Act (NGA) Section 4 rate filing in FERC Docket No. RP96-366. The Rate Case Settlement, approved by FERC Order issued September 24, 1997, provided that Transmission could not file a general rate case to increase its base tariff rates prior to October 1, 2000 (except in certain limited circumstances) and must file no later than October 1, 2001, since extended to October 1, 2003, pursuant to the Phase IV settlement discussed below. The Rate Case Settlement also provided that the rates charged pursuant to Transmission's Firm Transportation Service (FTS) rate schedule FTS-2 would decrease effective March 1, 1999 and March 1, 2000.

On October 1, 2003, Transmission filed a general rate case, proposing rate increases for all services, based upon a cost of service of approximately \$167.0 million for the pre-expansion system and approximately \$342.0 million for the incremental system. By order issued October 31, 2003, FERC accepted and suspended the effectiveness of Transmission's proposed rates for the statutory period of five months, effective April 1, 2004. Rehearing was requested by several customers, and FERC's rehearing order was issued April 20, 2004. On May 20, 2004, Transmission sought rehearing of this order. On August 13, 2004, Transmission filed a Stipulation and Agreement of Settlement ("Settlement"), which resolves all issues set for hearing in Docket No. RP04-12, rehearing on the April 20 2004 order, and all appeals of FERC 637 orders, pending before the D.C. Circuit Court. One party, AES, opposed the Settlement. On December 21, 2004, FERC issued an order conditionally approving the Settlement and rejecting AES' arguments. No rehearing requests were

(9) Regulatory Matters (continued)

filed; thus, the Settlement became effective on March 1, 2005. In its March 15, 2005 compliance filing, Transmission included specific process and account information in its revised tariff sheets to comply with the December order.

On December 1, 1999, Transmission filed an NGA Section 7 certificate application with the FERC in Docket No. CP00-40-000 to construct 215 miles of pipeline and 90,000 horsepower of compression and to acquire an undivided interest in the existing Mobile Bay Lateral owned by Koch Gateway Pipeline Company (now Gulf South Pipeline Company, LP), in order to expand the system capacity to provide incremental firm service to several new and existing customers of 270,000 MMBtu on an average annual day (Phase V Expansion). Expansion and acquisition costs were estimated at $437 million. Transmission requested that expansion costs be rolled into the rates applicable to FTS-2 (Incremental) service. On August 1, 2000, and September 29, 2000, Transmission amended its application on file with the FERC to reflect the withdrawal of two customers, the addition of a new customer and to modify the facilities to be constructed. The amended application reflected the construction of 167 miles of pipeline and 133,000 horsepower of compression to create additional capacity to provide 306,000 MMBtu of incremental firm service on an average annual day. The estimated cost of the revised project is $462 million. The Phase V Expansion was approved by FERC Order issued July 27, 2001, and accepted by Transmission on August 7, 2001. Segments of the Phase V Expansion project were placed in service in December 2001, March 2002, and April 2003, respectively. Total costs through December 31, 2004, were $424.0 million.

On November 15, 2001, Transmission filed an NGA Section 7 certificate application with the FERC in Docket No. CP02-27-000 to construct 33 miles of pipeline and 18,600 horsepower of compression in order to expand the system to provide incremental firm service to several new and existing customers of 85,000 MMBtu on an average day (Phase VI Expansion). Expansion costs were estimated at $105 million. Transmission requested the expansion costs be rolled into rates applicable to FTS-2 (Incremental) service. The application was approved by FERC Order issued on June 13, 2002, and accepted by Transmission on July 19, 2002. Clarification was granted and a rehearing request of a landowner was denied by FERC Order of September 3, 2002. The Phase VI Expansion was completed and placed in service during 2003 with the exception of the compressor station modifications at stations 12, 15, and 24. Compressor station modifications at stations 12 and 24 were completed and placed in-service on January 31, 2004, and February 1, 2004, respectively. Modifications at compressor station 15 were completed and placed in-service April 3, 2004. Total costs through December 31, 2004, were $76.7 million.

On November 25, 2003, the FERC issued Order No. 2004 making significant changes in the Standards of Conduct ("SOC") governing the relationships between pipelines and Energy Affiliates. The new SOC applies to a greater number of affiliates, requires more reporting, and requires appointment of a compliance officer. On February 9, 2004, Transmission made the required informational filing with regard to compliance by June 1, 2004. Implementation was required by September 2004, and Transmission has completed all training and has complied with the new requirements. On February 7, 2005, Transmission received a letter from the FERC advising that an audit for Order 2004 found that Transmission was in full compliance with all posting requirements.

On December 15, 2003, the U.S. Department of Transportation issued a Final Rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the regulation defines as "high consequence areas" ("HCA"). This rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a bill signed into law on December 17, 2002. The rule requires operators to identify HCAs along their pipelines by December 2004, to have begun baseline integrity

(9) Regulatory Matters (continued)

assessments, comprised of in-line inspection (smart pigging), hydrostatic testing, or direct assessment, by June 2004. Operators must risk rank their pipeline segments containing HCAs, and have the highest 50 percent assessed using one or more of these methods by December 2007. The balance must be completed by December 2012. The costs of utilizing these methods typically range from a few thousand dollars per mile to well over $15,000 per mile. In addition, some system modifications will be necessary to accommodate the inspections. Because identification and location of all the HCAs has not been completed, and because it is impossible to determine the scope of required remediation activities prior to completion of the assessments and inspections, the cost of implementing the requirements of this regulation is impossible to determine at this time. The required modifications and inspections are estimated to range from approximately $12 – 15 million per year, with remediation costs in addition to these amounts. In the August 13, 2004 Settlement of the rate case, Transmission has the right to make limited sections 4 filings to recover such costs beginning in April 2006 (if the threshold is met), via a surcharge, depreciation and return on up to $40 million in security, integrity assessment and repair costs, and Florida Turnpike relocation and modification costs (see Note 13).

On November 22, 2004, FERC issued a Notice of Inquiry ("NOI") in *Policy for Selective Discounting By Natural Gas Pipelines,* Docket No. RM05-2, *et al.* In the NOI, FERC requested comments from the industry on whether the selective discounting policy (including its policy in rate cases to allow pipelines to downward adjust volumes flowing at a discounted rate, for the purpose of determining rates), should continue, be modified, or eliminated entirely. On March 2, 2005, comments were filed on the NOI, including comments by the Interstate Natural Gas Association of America (supported by an economist's analysis) arguing that such policy should not be revised; that gas-on-gas competition does increase throughput and therefore results in lower prices to end users; that the elimination of the policy would likely result in the elimination of discounting by pipelines, filings for rate increases by pipelines, and the unraveling of the competitive market for pipeline capacity that FERC has heretofore fostered. Also on March 2, 2005, Chairman Wood stated that a NOPR will be issued in the next few weeks that will address a "broader look" at the discounting policy. Because it is unclear what proposal the FERC will issue, the Company cannot predict what effect the outcome of this proceeding will have on the Company's consolidated financial position, results of operations or cash flows, although Transmission (who recently settled a rate case proceeding) is not required to file another rate case until 2009.

(10) Property, Plant and Equipment

The principal components of the Company's Property, Plant and Equipment at December 31, 2004, and 2003 are as follows (in thousands):

	2004	2003
Transmission Plant	$ 2,783,798	$ 2,725,065
General Plant	25,136	25,619
Intangible Plant	23,738	20,612
Construction Work-in-progress	12,202	35,638
Acquisition Adjustment	1,252,466	1,252,466
	4,097,340	4,059,400
Less: Accumulated depreciation and amortization	(1,130,593)	(1,072,072)
Net Property, Plant and Equipment	$ 2,966,747	$ 2,987,328

(11) Deferred Charges and Other Assets – Other

The principal components of the Company's deferred charges and other assets – other at December 31, 2004, and 2003 are as follows (in thousands):

	2004	2003
Ramp-up assets, net*(1)*	$ 12,240	$ 12,552
Fuel tracker	11,165	6,479
Long-term receivables	71,501	77,080
Cash balance plan settlement	6,047	—
Cash collateral (see Note 3) *(2)*	—	595
Receipts for escrow	—	7,700
Balancing tools*(3)*	—	834
Other miscellaneous	3,387	3,140
Total Deferred Charges and Other Assets – Other	$ 104,340	$ 108,380

(1) Ramp-up assets is a regulatory asset Transmission was specifically allowed in the FERC certificates authorizing the Phase IV and V Expansion projects.

(2) Collateral posted to another party remains the property of the posting party, unless it defaults on the collateralized obligation.

(3) Balancing tools are a regulatory method by which Transmission recovers the costs of operational balancing of the pipelines' system. The balance can be a deferred charge or credit, depending on timing, rate changes, and operational activities.

(12) Other Deferred Credits

The principal components of the Company's other deferred credits at December 31, 2004, and 2003 are as follows (in thousands):

	2004	2003
Accrued expansion post construction mediation costs*(1)*	$ 3,296	$ 4,131
Customer deposits (see Note 14)	1,306	8,859
Phase IV retainage & Phase V surety bond	1,459	471
Balancing tools*(2)*	5,303	—
Deferred compensation	1,768	—
Miscellaneous	142	157
Total Other Deferred Credits	$ 13,274	$ 13,618

(1) Related to significant Phase IV, V, and VI expansion projects

(2) Balancing tools are a regulatory method by which Transmission recovers the costs of operational balancing of the pipelines' system. The balance can be a deferred charge or credit, depending on timing, rate changes, and operational activities.

(13) Commitments and Contingencies

In the normal course of business, the Company is involved in litigation, claims or assessments that may result in future economic detriment. The Company evaluates each of these matters and determines if loss accruals are necessary as required by SFAS No. 5, *Accounting for Contingencies.* The Company does not expect to experience losses that would be materially in excess of the amount accrued at December 31, 2004.

Transmission and Trading have filed bankruptcy related claims against Enron and other affiliated bankrupt companies totaling $220.6 million. Transmission's claim includes rejection damages and delinquent amounts owed under certain transportation agreements, an unpaid promissory note, and other fees for services and imbalances. Subsequent to Transmission's filing its claims,

(13) Commitments and Contingencies (continued)

ENA's firm transportation agreements were permanently relinquished to a creditworthy party, which significantly reduced Transmission's rejection damages (see Note 8). Trading's claim is for rejection damages on two physical/financial swaps and a gas sales contract, as well as certain delinquent amounts owed pre-petition. Transmission and Enron resolved all claim amounts; settlement documents were finalized but await bankruptcy court approval (see Note 8). In March 2005, ENA filed objections to Trading's claim.

On March 7, 2003, Trading filed a declaratory order action, involving a contract between it and Duke. Trading requested that the court declare that Duke breached the parties' natural gas purchase contract by failing to provide sufficient volumes of gas to Trading. The suit seeks damages and a judicial determination that Duke has not suffered a "loss of supply" under the parties' contract, which could, if it continued, have given rise to the right of Duke to terminate the contract at a point in the future. On April 14, 2003, Duke sent Trading a notice that the contract was terminated as of April 16, 2003 (due to Trading's alleged failure to timely increase the amount of a letter of credit); although it disagreed with Duke's position, Trading increased the letter of credit on April 15, 2003. Duke has answered and filed a counterclaim, arguing that Trading failed to timely increase the amount of a letter of credit, and that it has breached a "resale restriction" on the gas. Trading disputes that it has breached the agreement, or that any event has given rise to a right to terminate by Duke. On May 1, 2003, Trading notified Duke that it was in default under the Agreement, for failure to deliver the base volumes beginning April 17, 2003. However, Duke continued to refuse to perform under the contract. On June 2, 2003, Trading notified Duke that, because Duke had not cured its default, Trading was terminating the agreement effective as of June 5, 2003. On August 8, 2003, Trading sent its final "termination payment" invoice to Duke in the amount of $187 million. On August 18, 2003, Duke filed a Third-Party Petition against Sonatrading and Sonatrach, its Algerian suppliers ("Sonatrach"), which Trading opposed since, *inter alia,* even in the event of a failure to receive supplies from Algeria, Duke was required to furnish supplies to Trading for a stated period of time. On October 6, 2003, Trading filed its Amended Petition, alleging wrongful termination and containing the termination damages. In October 2003, Sonatrach filed a special appearance challenging jurisdiction. On November 25, 2003, Trading filed its Second Amended Complaint, alleging, among other things, that Duke was required to give reasonable notice to Trading to upgrade the letter of credit, before terminating the contract. On December 5, 2003, Duke filed its answer. Sonatrach's motion to dismiss for lack of jurisdiction was filed March 2, 2004; and Duke's response was filed March 31, 2004. Discovery is ongoing, and the judge continues to hold informal discovery in an attempt to resolve the case. On March 8, 2004, Trading made demand on PanEnergy, who, along with Duke is a signatory to the agreement, asking for PanEnergy to ensure (per the contracts) that Duke has sufficient assets to pay Trading's claim. Because assurances were not forthcoming, on March 16, 2004, Trading filed suit against PanEnergy in state court and on April 21, 2004, Duke retaliated by amending its complaint to include a claim against Citrus under the same contract provision, and asked to consolidate Trading's suit against PanEnergy. On March 23, 2004, Trading filed a motion for Partial Summary Judgment against Duke, seeking a ruling that Duke was required to provide Trading with notice before terminating the agreements. The Court ordered that discovery be completed in July 2004. On July 28, 2004, Trading filed its amended Motion for Partial Summary Judgment; Duke's response and Cross Motion for Partial Summary Judgment was filed on August 19, 2004. Trading's reply to Duke's cross motion was filed September 3, 2004, to which Duke replied on September 17, 2004, to which Trading replied on September 29, 2004. The Judge has not ruled on the motions, and no order has been issued with respect to oral argument on the motions. Trading's December 2004 request for a status conference was denied. This is a disputed matter, and there can be no assurance as to what amounts, if any, Trading will ultimately recover. Management believes that the amount ultimately recovered will not

(13) Commitments and Contingencies (continued)

be materially different than the amount recorded as a receivable at December 31, 2004, and that the ultimate resolution of this matter will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows. Management further believes that claims made by Duke against the Company with regard to this matter do not constitute a liability which would require adjustment to the Company's December 31, 2004 consolidated financial statements in accordance with SFAS No. 5, *Accounting for Contingencies.*

The Florida Department of Transportation, Florida's Turnpike Enterprise (FDOT/FTE) has various turnpike widening projects in the planning stages, which may, over the next ten years, impact one or more of Transmission's mainline pipelines that are co-located in FDOT/FTE rights-of-way. Transmission is currently aware of seven projects with a total of approximately 35 miles that are scheduled for construction between 2005 and 2008 that could potentially impact Transmission's mainlines along the Beeline Expressway and the Sunshine State Parkway. The FDOT/FTE and Transmission are currently in discussions with respect to widening projects covering approximately 13 miles that are currently scheduled for construction during 2005 and which will impact Transmission's 18" and 24" pipelines in Broward County. Two other FDOT/FTE projects, covering approximately 8.1 miles in Broward County and scheduled for construction during 2006 or 2007 will also impact Transmission's 18" and 24" pipelines. An additional FDOT/FTE project to install a new toll plaza in Broward County is scheduled for 2008 construction. The FDOT/FTE has informed Transmission that the plan is to complete the widening projects through Broward County and later, Palm Beach County, by 2010.

Under certain conditions, the existing agreements between Transmission and the FDOT/FTE require the FDOT/FTE to provide any new right-of-way needed for relocation of the pipelines and for Transmission to pay for rearrangement or relocation costs. Under certain other conditions, Transmission may be entitled to reimbursement for the costs associated with relocation, including construction and right of way costs. Transmission has presented the FDOT/FTE with an invoice for reimbursement of the costs incurred by Transmission in connection with a previous relocation project, and the FDOT/FTE has denied liability for such costs under the provisions of the existing easements. The total actual amount of miles of pipe to be impacted ultimately for all of the FDOT/FTE widening projects, and the associated relocation and/or right-of-way costs, cannot be determined at this time.

(14) Concentrations of Credit Risk and Other Financial Instruments

The Company has a concentration of customers in the electric and gas utility industries. These concentrations of customers may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. Credit losses incurred on receivables in these industries compare favorably to losses experienced in the Company's receivable portfolio as a whole. The Company also has a concentration of customers located in the southeastern United States, primarily within the state of Florida. Receivables are generally not collateralized. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments, deposits, or other forms of security to the Company. Transmission sought additional assurances from customers due to credit concerns, and had customer deposits totaling $1.3 and $8.9 million and prepayments of $1.2 and $1.6 million for 2004 and 2003, respectively. The Company's Management believes that the portfolio of Transmission's receivables, which includes regulated electric utilities, regulated local distribution companies, and municipalities, is of minimal credit risk.

(14) Concentrations of Credit Risk and Other Financial Instruments (continued)

The carrying amounts and fair value of the Company's financial instruments at December 31, 2004, and 2003 are as follows (in thousands):

	2004		2003	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt	1,028,000	1,193,793	1,167,500	1,396,453

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable and revolving credit agreements reasonably approximate their fair value. The fair value of long-term debt is based upon market quotations of similar debt at interest rates currently available.

(15) Comprehensive Income

Comprehensive income includes the following (in thousands):

	2004	2003	2002
Net income	$ 126,844	$ 76,216	$ 96,587
Other comprehensive income:			
Derivative instruments:			
Deferred loss on anticipatory cash flow hedge (see Note 4)	—	—	(12,280)
Recognition in earnings of previously deferred losses related to derivative instruments used as cash flow hedges	1,447	1,206	540
Total comprehensive income	$ 128,291	$ 77,422	$ 84,847

(16) Accounting Pronouncements

On March 3, 2005, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) FIN 46(R)-5, "Implicit Variable Interests under FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities"' to address whether a reporting enterprise should consider whether it holds an implicit variable interest in a variable interest entity (VIE) or potential VIE when specific conditions exist. The determination of whether an implicit variable interest exists should be based on whether the reporting enterprise may absorb variability of the VIE or potential VIE. This FSP is effective, for entities to which the interpretations of FIN 46(R) have been applied, in the first reporting period beginning after March 3, 2005. There is no impact on the Company's financial statements of adopting this FSP.

In November 2004, the FERC issued an industry-wide Proposed Accounting Release that, if it becomes effective as written, would require pipeline companies to expense rather than capitalize certain assessment costs related to mandated pipeline integrity programs (under the Pipeline Safety Improvement Act of 2002). The accounting release was proposed to be effective January 1, 2005, following a period of public comment on the release. Comments were filed on January 19, 2005, including pipeline association comments suggesting that such costs be capitalized. The Company is awaiting a final release and cannot, at this time, predict the outcome or determine what impact such release will have on its consolidated financial statements.

On October 22, 2004, the American Jobs Creation Act of 2004 (the Act) was signed. The Act raises a number of issues with respect to accounting for income taxes. On December 21, 2004, the FASB issued a FASB Staff Positions (FSP) regarding the accounting implications of the Act related to the deduction for qualified domestic production activities (FSP FAS 109-1). The guidance in the FSP applies, as it relates to domestic production activities, to financial statements for

(16) Accounting Pronouncements (continued)

periods subsequent to December 31, 2004. The guidance in the FSP otherwise applies to financial statements for periods ending after the date the Act was enacted.

In FSP FAS 109-1, "Application of FASB Statement No. 109, 'Accounting for Income Taxes,' to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004," the FASB decided that the deduction for qualified domestic production activities should be accounted for as a special deduction under Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes," and rejected an alternative view to treat it as a rate reduction. Accordingly, any benefit from the deduction should be reported in the period in which the deduction is claimed on the tax return. In most cases, a company's existing deferred tax balances will not be impacted at the date of enactment. For some companies, the deduction could have an impact on their effective tax rate and, therefore, should be considered when determining the estimated annual rate used for interim financial reporting. The Company is currently evaluating the impact, if any, of this FSP on its consolidated financial statements.

In Statement of Financial Accounting Standards (SFAS) No. 153, the FASB modified the existing guidance on accounting for nonmonetary transactions in Accounting Principals Board Opinion No. 29, "Accounting for Nonmonetary Transactions," to eliminate an exception under which certain exchanges of similar productive nonmonetary assets were not accounted for at fair value. SFAS No. 153 instead provides a general exception for exchanges of nonmonetary assets that do not have commercial substance. This statement must be applied to nonmonetary assets exchanges occurring in fiscal periods beginning after June 15, 2005. The Company is currently evaluating the impact, if any, of this statement on its consolidated financial statements.

SOUTHERN NATURAL GAS COMPANY

EXHIBIT LIST
December 31, 2004

Exhibits not incorporated by reference to a prior filing are designated by an asterisk. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
3.A	Restated Certificate of Incorporation dated as of March 7, 2002 (Exhibit 3.A to our 2001 Form 10-K).
3.B	By-laws dated as of June 24, 2002. (Exhibit 3.B to our 2002 Form 10-K).
4.A	Indenture dated June 1, 1987 between Southern Natural Gas Company and Wilmington Trust Company (as successor to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.1 to our Registration Statement on Form S-3 filed January 15, 2002, File No. 333-76782); First Supplemental Indenture, dated as of September 30, 1997, between Southern Natural Gas Company and the Trustee (Exhibit 4.1 to our Registration Statement on Form S-3 filed January 15, 2002, File No. 333-76782); Second Supplemental Indenture dated as of February 13, 2001, between Southern Natural Gas Company and the Trustee.
4.B	Indenture dated as of March 5, 2003 between Southern Natural Gas Company and The Bank of New York Trust Company, N.A., successor to The Bank of New York, as Trustee (Exhibit 4.1 to our Form 8-K filed March 5, 2003).
10.A	Amended and Restated Credit Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 99.B to our Form 8-K filed November 29, 2004); Amended and Restated Subsidiary Guarantee Agreement dated as of November 23, 2004, made by each of the Subsidiary Guarantors in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 99.D to our Form 8-K filed November 29, 2004).
10.B	Amended and Restated Security Agreement dated as of November 23, 2004, made by among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 99.C to our Form 8-K filed November 29, 2004).
10.C	$3,000,000,000 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN Amro Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.1 to El Paso Corporation's Form 8-K filed April 18, 2003); First Amendment to the $3,000,000,000 Revolving Credit Agreement and Waiver dated as of March 15, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.1 to our 2003 First Quarter Form 10-Q); Second Waiver to the $3,000,000,000 Revolving Credit Agreement dated as of June 15, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.2 to our 2003 Second Quarter Form 10-Q); Second Amendment to the $3,000,000,000 Revolving Credit Agreement and Third Waiver dated as of August 6, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents. (Exhibit 99.B to our Form 8-K filed August 10, 2004).
21	Omitted pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Exhibit Number	Description
*31.A	Certification of Chief Executive Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*32.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002.
*32.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 29th day of March, 2005.

SOUTHERN NATURAL GAS COMPANY

By /s/ JOHN W. SOMERHALDER II
John W. Somerhalder II
Chairman of the Board

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ JOHN W. SOMERHALDER II (John W. Somerhalder II)	Chairman of the Board and Director (Principal Executive Officer)	March 29, 2005
/s/ JAMES C. YARDLEY (James C. Yardley)	President and Director	March 29, 2005
/s/ GREG G. GRUBER (Greg G. Gruber)	Senior Vice President, Chief Financial Officer, Treasurer and Director (Principal Financial and Accounting Officer)	March 29, 2005